STATE OF ALASKA

REGULATORY COMMISSION OF ALASKA

Before Commissioners: T.W. Patch, Chairman
Paul P. Lisanskie
Robert M. Pickett
Norman Rokeberg
Janis W. Wilson

REGULATORY COMMISSION OF ALASKA
701 West Eighth Avenue, Suite 300
Anchorage, Alaska

PUBLIC HEARING
Docket No. R-13-002

January 29, 2014
9:33 a.m.

BEFORE ROBERT ROYCE
Administrative Law Judge

P R O C E E D I N G S

(On record - 9:33 a.m.)

ALJ ROYCE: Good morning.

It's approximately 9:33 a.m., Wednesday, January 29th, 2014, in the Commission's hearing room in Anchorage, Alaska. This is the time and place set for a public hearing in the matter of the petition filed by Alaska Environmental Power, LLC to amend 3 AAC 50.750 to 3 AAC 50.820, addressing cogeneration and small power production, given Docket No. R-13-002.

I'm Robert Royce, administrative law judge for the Commission presiding. With me on the dais this morning are Commissioners Janis W. Wilson, Paul F. Lisankie, Robert M. Pickett, Norman Rokeberg, and Chairman T.W. Patch.

This public hearing was scheduled pursuant to Order No. 1, issued in this proceeding on October 2nd, 2013. Order No. 1 invited comments in four areas. Those areas are the avoided cost definition and methodology, integration costs for renewable energy production by small and independent power producers. The third area was curtailment provisions for production by qualifying facilities, and the fourth area was an open bidding process for renewable energy projects.

We also required Alaska Environmental Power, who are the petitioners in this case, to provide specific language for its proposed revisions to our regulations, which it did, and those proposed revisions are attached as Appendix A to Alaska Environmental Power's initial comments filed November 18th, 2013.

The purpose of this morning's public hearing is to provide an opportunity for commenters to make presentations and summarize their comments. There will also be an opportunity for Commissioners to ask questions.

Alaska Environmental Power will make its presentation first, followed by the Alaska Independent Power Producers Association, which is represented by Carolyn Elefant, which I believe is on the phone from Washington, D.C. We'll then hear from Cook

Inlet Region, Inc.

There's also a sign-up sheet in the back, and I encourage everyone that wants to make comments to sign that sign-up sheet, and I will then, after we get done with the first three presentations, turn to the sign-up sheet. I'll call your name. Please come forward and identify yourself for the record.

We're going to generally hear from commenters who are in support of the proposed revisions and then, time permitting, we'll hear from other commenters who have taken contrary positions on the reg. Everybody should be aware that this hearing will be continued on February 4th. Please let me know if there's any scheduling conflicts. We're going to try to accommodate everybody, so we might have to go back and forth, but general order, we're going to hear from supporters and then we'll hear from people with contrary positions.

There's also several people listening on the phone today who may want to make comments. We'll -- after we hear from the presenters, I will ask if anybody wants to make presentations on the phone.

I know, Ms. Elefant, are you on the line? Do we have --

MS. ELEFANT: Yes, I'm sorry for the lag. I took your advice and I went on mute. So I am on the line. Thank you.

ALJ ROYCE: Okay. Thank you. And if everybody else that is on the phone, if they can place their phone on mute so we don't hear the background noise, that would be appreciated.

So with that, Ms. Clemmer, are you ready to proceed with your presentation? Okay. Please identify yourself for the record and proceed.

MS. CLEMMER: Okay. Thank you. My name is Theresa Clemmer. I'm an attorney with Bessenyey & Van Tuyn. I'm representing Alaska Environmental Power, LLC in this proceeding. We are the petitioners, and we want to thank you for opening this rulemaking docket and for the opportunity to speak today before all the Commissioners.

And I'll let Mike Craft introduce

himself.

MR. CRAFT: Hi, good morning. My name is Mike Craft, and I am the managing partner for Alaska Environmental Power. I'm also 50-percent owner in the business. It's a pleasure to be here, and I appreciate you guys taking the time to allow us to present our case from the table. Thank you.

ALJ ROYCE: Thank you, Mr. Craft.

Please go ahead, Ms. Clemmer.

MS. CLEMMER: Okay. Thank you. All right.

I'm going to start with our presentation. This is an overview of what I'm going to be talking about. You in the Order specifically asked for information about the RCA's legal authorities and duties, so I'm going to cover that initially, and then move into the four topics that you just listed that were the subject of our petition: Avoided cost, integration fees, curtailment. We have scaled back the fourth one to oversight and transparency rather than a full-blown competitive bidding proposal. And then finally some additional information about renewable resources in general and then a quick summary.

So, legal authorities. As I'm sure the Commissioners are well aware, they have broad authority to do all things necessary and proper to carry out the purposes of regulating utilities. I just wanted to point out a couple of things.

One is that the regulation of rates is only one aspect of it. There's a much broader authority there to regulate the practices and services and all kinds of activities of public utilities. So I think there's plenty of authority to modify these regulations.

The RCA also has guidance from the Legislature directing them to promote the conservation of resources used in the generation of electric energy. What that really means is conserving fossil fuels -- reducing reliance on fossil fuels and promoting renewable energies, which is why we're here today.

So the Regulatory Commission is also guided by federal law. This is the

PURPA Section 210, which is the statute setting out some requirements for state utility commissions around the country relating to the relationship between utilities and this group of qualifying facilities, which are defined to be small, renewable energy producers and cogeneration facilities.

Section 210 of PURPA is designed to promote development of alternative energy resources by overcoming the historical reluctance of electric utilities to purchase power from nontraditional facilities. So there's a lot packed in there. That's a quote from the U.S. Supreme Court interpreting PURPA shortly after it was enacted.

One thing is the focus on alternative energy resources, but also recognizing that those alternative energy resources, the primary drivers of that development around the country have been independent power producers.

Recent data from 2012 show that about 83 percent of wind power, for instance, around the country has been developed by independent power producers, and the remaining 17 percent is a combination of utilities, cities, universities, and that kind of thing. So really the lion's share of wind development around the country has been independent power producers. So that's what Congress recognized over 30 years ago, and it has borne out to be true today.

Congress also directs FERC -- this is part of the strategy. Congress directs FERC to promulgate rules requiring utilities to operate or purchase electricity from qualifying cogeneration and small power production facilities. So this is a mandate for FERC to develop some regulations defining how that relationship is going to work.

One of the key principles of that is nondiscrimination, and that's a key theme of our presentation today, is that the rates for those purchases from these small qualifying facilities are supposed to be nondiscriminatory.

All right. Moving on. So the predecessor to the RCA, the APUC, back in

1982 adopted regulations, which are what we have today in Part 50, Article 2. The purpose mirrors the PURPA statute and the FERC regulations, which is to encourage cogeneration and small power production, and incorporates this language about nondiscrimination and reasonable rates and terms and conditions.

So this reflects the fact that the Commission has the authority to act in this area, and also has guidance from Congress and from FERC in some of the obligations that it needs to fulfill. In addition to the federal laws and the general, broad State authority for the Commission, the Legislature in 2010 really made a concerted effort to develop a State energy policy.

They adopted this into legislation, and so it created -- and this was a major effort. It wasn't something they did, you know, within a couple days. The legislators traveled around the state. They held nine public hearings. You know, this was a big deal at the time, as some of you probably remember.

A lot of the emphasis was on encouraging economic development by promoting renewable energy and alternative energy resources. Also, you can see here at the bottom there was a focus on thinking about and setting out guidelines for the regulatory processes that encourage private sector development of the state's energy resources. So the Legislature really was intending to provide guidance to agencies in carrying out their vision of an Alaska state energy policy.

At the same time, as part of HB 306, the Energy Policy Act, the Legislature adopted a statement of legislative intent indicating that its renewable energy goal was going to be 50 percent by 2025, but it wanted the state to make every effort to become a leader in renewable alternative energy development. This was meant to be guidance for the agencies, again, to guide them in how they carry out their work. All right.

So I'm emphasizing this a bit, because there's a lot of discussion in the briefing about the regulatory policies not particularly being applicable to this proceeding or really just being verbiage that doesn't carry a lot of weight, but I think that it's contrary to what people thought at the time they were adopting HB 306.

This is Bill Popp of the Anchorage Economic Development Corporation explaining that this really was meant to be an overarching energy policy that brings all the executive branch agencies and the Legislature in terms of its funding priorities all on the same page in terms of where the direction of the State should be headed. Then, again, during an exchange during the testimony in public hearings -- or in the Legislative hearings, they described this 50 percent by 2025 goal as a measuring stick for the regulatory agencies, and particularly the ones that have to do with energy and energy policy.

Then more recently the 50 percent by 2025 goal comes up all the time, and the leaders of the state have been referring to it and have been guided by it. I keep emphasizing that it's a commitment that the State has set, and that it's determined to meet. So it's not something that was just written on the back of a napkin and forgotten. This is something that really is considered the policy of the State of Alaska.

ALJ ROYCE: Excuse me. Can you mute your phone? We can hear your conversation, whoever is talking on the phone. Sorry.

Please proceed.

MS. CLEMMER: That's okay. Okay.

And most recently, this was back in November, Senator McGuire emphasized again the 50 percent goal, and also noted that there are barriers that discourage investment in these resources and are holding us back from achieving these goals. I think that was in part referring to regulatory changes that need to be made to open up the gates a little wider to independent power producers. Okay.

So moving on to avoided cost, we're going to dive a little deeper into the actual requirements of PURPA and the FERC regulations. As a starting point, as we were just talking about, Congress set out this goal that utilities would have an obligation to purchase power from this defined group of small power producers and that there was this nondiscrimination principle, but it left it up to FERC to decide exactly how to implement that law.

Congress did also define that the term incremental avoided cost would be kind of the guideline for the price for that power that they would purchase, but then it left FERC to further define that and to develop regulations implementing the rule.

Another aspect of the statute is that the regulatory authorities shall implement the FERC rules, so this is an obligation there for each state regulatory commission around the country to implement the FERC rules.

And what FERC did, it considered a variety of different ways of approaching the avoided cost issue, and decided after much deliberation to set it at a level that equals the avoided cost rate unless the parties mutually agree otherwise. The idea was that the overarching goal of the legislation was not to just save a few pennies in the short term in terms of energy; it was to get a nascent industry off the ground, and it really wanted to incentivize renewable energy development by independent power producers.

So it wanted to give them the best price that it could without harming consumers. So it maximized the incremental avoided cost, which is the rate that's cost neutral. You know, if renewable energy is coming in and displacing other forms of power, if it can be done in a way that doesn't harm consumers, then in order to incentivize those independent power producers, FERC decided it's going to give them as much as it could. There are a lot of public benefits that Congress had in mind in terms of diversifying energy for purposes of energy security and reducing reliance on the volatile fossil fuel market with the increasing prices and unpredictable pricing.

Congress saw a lot of value in renewable energy for a lot of reasons other than just saving a few pennies, although often renewable energy can be cost saving as well. So we have incremental costs as the touchstone in both the PURPA statute and in the FERC regulations.

So I maybe am oversimplifying slightly, but I'm responding to a lot of the briefing that is emphasizing how complex this is and how overwhelmingly complicated this is and how, you know, this is going to take a long time to figure out and might be impossible to do. I just want to say as a starting point that it's really not that complicated.

We're talking about incremental avoided cost versus system average avoided cost. In terms of regulatory change, it's just a few words that can accomplish that change. Also, the principle of incremental cost is really not that difficult to understand.

We're talking about the displacement of the highest cost increment of the utility's power rather than averaging all of the costs across the whole utility's portfolio to come up with an average price. So this is -- this was in the preamble to FERC's regulations when it was first adopting them.

It considered this issue of, well, what about system average costs? And from the very outset said system average costs would not be allowed, but incremental cost meant something different, and that system average cost would not be an adequate way to implement this law. Then since then we've had the Ninth Circuit and other courts repeatedly emphasize that QFs are entitled to receive the full avoided cost rate at least as a starting point for negotiations. If they want to trade off other benefits, that's up to them, but they're entitled to at least as a starting point get the full avoided cost rate.

All right. There's another aspect of avoided cost that I want to point out in addition to just the definition of incremental versus system average. There's a provision that's entirely missing from the regulations that the APUC adopted 30-some odd years ago.

That provision states that QFs shall have the option to sell power on an as-available basis, which means on any given day if they want to sell power, they can operate to the utility, and the utility would have an obligation to purchase it with a price to be determined on the incremental cost that day, or the QFs would have an option to purchase the power through either contract or a legally enforceable obligation, which is a term of art and is considered by the courts and by FERC to be something different, which I'll talk about in just a minute.

But then, again, it gives QFs the option of, if you're going to enter into a contract or some kind of long-term obligation, you have the choice of having your avoided cost pricing set at the outset based on a projection of what the avoided costs are going to be, or you could go with a daily fluctuating avoided cost rate. But I just want to note that three times in this regulation it refers to the option of the QF.

In the case law it makes it very clear that the purpose of having the term "legally enforceable obligation" in there instead of something like contract or agreement, is that if there is a situation where the utility and the QF cannot reach agreement and they've negotiated and they can't figure it out, the default position is that the project can go forward and that the utility cannot act as a roadblock.

So if the QF is willing to commit itself to a set of terms and move forward, then the utility would have an obligation to purchase. That's not how it's worked in Alaska, and it has not been in the regulations until now, but it is a provision that is required to be in there. The various decisions that I've seen -- there have been enforcement actions by FERC against state commissions that either don't have this provision or are not implementing it or enforcing it. So this is an important gap, I think, that we could remedy in this proceeding.

I've already emphasized the

nondiscrimination provision. The way that applies in Alaska is that another aspect of avoided cost is that the FERC regulations set out a set of factors that are used to determine what the avoided cost rate is going to be. There's a whole list of them. The State has adopted most of them in a slightly varied form, but more or less they're mostly in there, but in Alaska they're only applied to firm power. They are not applied to nonfirm power. That's a distinction that is not made in the FERC regulations.

Because of this overriding nondiscrimination principle, that distinction between firm and nonfirm power and the application of the factors to one group of QFs and not to another group of QFs seems to violate that nondiscrimination principle. So that is something that we'd like to see remedied.

There's been some discussion back and forth about whether the particular factors that we proposed are not verbatim the same as FERC's, but neither are the current ones, and there is some wiggle room in there.

The FERC regulations in terms of the factors are supposed to be implemented to the extent practicable. It shall be implemented to the extent practicable.

So, in general, the factors are supposed to be applied, but there's some wiggle room for states to vary them. But we believe that our wording variations are minor differences. If the Commission were to adopt the FERC factors verbatim and apply them uniformly to both firm and nonfirm power, that would certainly be consistent with federal law. So, you know, we wouldn't fall on our swords over a few word changes that we thought might enhance them a little bit.

So the counterarguments as to why the avoided cost definition shouldn't be changed and some of these other avoided cost changes shouldn't be made. This is what -- you know, I'm just trying to distill from the briefs what the arguments were.

The first one is that the two definitions are really the same. They're equivalent; they mean the same thing. That argument appeared in multiple briefs, and it just is surprising to say that the system average approach is really the same thing as the incremental approach, when from the very beginning FERC said the incremental approach is what you're supposed to use. The system average approach is different and is not what you're supposed to be using. So I just think that's pretty plain on its face, and that argument doesn't really go anywhere.

The second kind of related argument is that incremental avoided costs would lead to the same or similar results. This is the argument that the system average approach is a workable proxy for the incremental approach. There's really -- these are just kind of bare statements. I haven't seen any evidence to support the claim that the calculations would actually come out the same. These same exact arguments were the reason why the temporary departure was chosen back in 1982.

So the idea behind this temporary departure was that this would just be an easy way to do it at first, and then eventually we're going to go move toward the requirement incremental approach, but it just doesn't make any sense now to say that the approach should remain the same when it was never really supposed to be that way in the first place, and it's just common sense that the incremental approach is going to be different than a system average approach.

So we have common sense on the one hand. We only have one example. Obviously AEP has been in negotiations with Golden Valley, so this is our experience and these are the examples we have to draw upon. But this is a comparison of system average rates. These are the RCA-approved QF 2 rates for the last several fall, winter, and spring quarters, which those are the three quarters that are really relevant for wind power. That's when the bulk of the power is produced.

So we're looking at rates under the system average approach in the range of 11 to 13 cents a kilowatt hour. That may seem high to people used to other areas of the grid, but those are low compared to Golden Valley's highest rates. They're brought down in that averaging process by the cheaper power that's available from these plants that were built back in the 1950s and 1960s.

So in contrast to that we have the fall, winter, and spring quarter fuel costs. This is taken from the fuel and purchase power submissions to the RCA that Golden Valley makes each quarter. We're looking at a lot higher prices, because the cost -- primarily because of the cost of diesel. So you can see the Fairbanks and Delta plants are extremely high, just off the charts. It's true that they don't account for a huge percentage of Golden Valley's overall costs, but the number is about 3 percent of their overall fuel and purchase power costs. Because the numbers are so high, they do have an impact on the overall rates.

The second column ranges from somewhere around in the 20s to all the way as high as 66 cents a kilowatt hour, and that's a higher percentage. That's about 16 percent of Golden Valley's overall fuel and purchase power costs. Then at the North Pole expansion facility we're talking 16, 17 cents a kilowatt hour. That's responsible for about 39 percent of Golden Valley's fuel and purchase power costs.

So together -- just make sure I'm doing my math right -- that is about 58 percent of Golden Valley's fuel and purchase power costs. So these are the highest cost facilities. These are the types of things that would be displaced, maybe not entirely, but at least you could reduce your reliance on these sources by using the wind power project by my client or other renewable projects that came forward. So this is really just to illustrate the difference between a system average approach and what could potentially be the pricing range for an incremental avoided cost rate.

Another argument that was made particularly in the opening briefs, but I didn't see in the reply briefs, was that the QFs should not need to worry about changing the language of the regulations because there's this caveat in there that the

Commission can always order something otherwise. But essentially that is putting the burden on the QFs to demonstrate on a case-by-case basis that incremental costs would be appropriate in a particular situation and wouldn't be too burdensome, and they can request that the Commission require that methodology.

That just legally has already been decided. That approach was rejected because it would be time consuming and it would be discouraging to the development of QF power, which is contrary to the purpose of PURPA. Also, in addition to the fact that the law is clear on this point, it's just a matter of fundamental fairness that QFs shouldn't have to fight for what they're already legally entitled to. That should be what the law says, and that should be the starting point, and deviations from that are what the Commission could be approached about.

Another argument that I saw was that the judgment of utility management is vast, and there's no real need for revised regulations; essentially kind of a just trust us argument. Of course that's true that there are instances in which utilities and QFs can work very well together and very cooperatively, and there have been successful stories in that regard. But the law recognizes that that's not always the case, that the whole purpose of the law was to overcome this historical reluctance of utilities to let go of control over generation in their utility systems.

It remains a substantial problem in Alaska. We rank last out of all 50 states in IPP generation. We're only about 3 percent IPP generation compared to the national average, which is 39 percent. So it shows that there is a need for a framework to -- in which the utilities and the QFs are negotiating that sets the ground rules and ensures that things are fair and that the goals of the law are going to be achieved.

Argument 5, and this probably was the most emphasized argument in the briefs, is that calculating it would just be too difficult and burdensome. It's just an impossible task, was essentially the take-home point.

I think there's a couple problems with that argument. One is it's required. Even if it's challenging, the RCA has this obligation to use the incremental avoided cost standard. The implementation considerations are important, but they do not give the RCA the ability to just ignore what Congress has said and what FERC has said. So that's one reason.

But even if they could, even if the RCA did not have to incorporate this incremental cost standard, the utilities seem to be exaggerating the difficulties associated with incremental avoided cost calculations. First of all, they're routinely perform throughout the country. Everywhere else people seem to be able to do it, and there are several models available. We don't think it's necessary in this proceeding to get into the particular technical details of the models, but they're available, and there's a lot of learning that could be done after the standard is established.

Another issue is that this would have to be done. If the QFs were to choose the as-available approach, that they would have to do this on a daily basis, and it would be very time consuming and burdensome. But because these QFs are dealing with banks and they're trying to get long-term contracts and they're trying to get financing, they're almost always going to want more certainty than daily pricing. They're going to want long-term, fixed rates based on a projection of what the incremental costs are going to be.

So it's really just not very likely that you're ever, or maybe once in a great while ever going to have to do avoided cost pricing on a daily basis or on an as-available basis.

It was also suggested that it would be tricky even to try to do incremental avoided cost pricing on a quarterly basis the way system average pricing is done typically now, but there are ways that that can be addressed too for these small 100 kilowatt or smaller projects. If you're doing standard offer pricing, you could go to annual updates. You could do projects and update them less frequently. There are probably other mechanisms that could be done to make this feasible.

Another reason the feasibility issue seems to be overblown is that that argument may have really been true back in the 1980s when this law was first up for consideration, but we are now in 2014, a third of a century later. Technology has come a long way, and the utilities have often touted this, that they have SCADA systems and they have computer systems and they can do economic dispatching. So the world is just very different than it was in 1980. So we think it's a challenge that can be met and the law requires it.

So, technical workshops. That's another -- in the same vein of arguing that it's very difficult and very challenging and complex, the utilities are arguing that we need to do technical workshops before making any regulatory revisions. We see this as a form of delay and that's really not necessary.

What we're asking for is some regulatory changes. We want to incorporate the federal incremental avoided cost standard. We want to ensure an QF's right to choose avoided costs and also to have the final say about whether their project can go forward under this LEO. We want the factors to be applied in a uniform fashion and nondiscriminatory fashion to both firm and nonfirm power. Those things are all regulatory language changes that can be done in a very straightforward way by adopting what FERC regulations say, that we don't need to have workshops to be able to do that.

So we think regulation now and then implementation later, which can be done through orders; it can be done through tariff proceedings. It may give an opportunity for the Commission and the utilities to spend some time working on this and developing this and learning about this, and the approaches could evolve over time, and they could be tailored to specific circumstances. So it may not be wise to try to jam all that into this proceeding.

Okay. So we're done with avoided cost. Integration fees. This is the second component of our petition. We think and have seen that integration fees can be an area where there's a lot of dispute, a lot of contention, and it presents one of the areas where there's the most risk of discriminatory practices.

These are some excerpts from NREL, who has looked closely at a lot of these issues. Their conclusion has been that integration costs, you know, are something that's difficult to wrap your head around. There are challenges in calculating them. But even if you can calculate them, a big question is: How do you apply them fairly to these wind and solar and renewable facilities when there are integration costs associated with pretty much every generation facility on a system? They have some form of integration cost. The utilities normally just absorb those costs and treat them as overhead, and they don't allocate them out separately to each facility.

So when they start this task of allocating them to wind or any other kind of facility, there's a tendency to throw a lot in that bucket, and to maybe allocate some things to wind that really should be shared or should continue to be shared among the whole system. So NREL cautioned that if you're going to impose integration fees on renewable energy, you should be very careful to ensure that it's not discriminatory.

So this is just a graphic that came from that NREL report. It's discussed at length in our brief, so I won't go in great detail. But I just want to emphasize, the point here is that this issue of utilities exaggerating integration fees and imposing integration fees that are too high, or at least demanding them in the course of negotiations, which may be enough to kill a project, is such a widespread problem that NREL felt that it was important to do a survey of the entire western grid and develop this 250-page report analyzing the issue of whether fuel cost savings that you get from renewables are the same as, less than, more than, than the cycling costs, which are one of the biggest components of integration costs. That's the cost of ramping facilities up and down more than you would normally have to to provide the backup power for wind and solar or other nonfirm sources.

So cycling costs is one of -- and particularly in Alaska it's one of the biggest sources of integration costs, because you're not likely to shut off firm power entirely; you're likely to just ramp it down. You'll get fuel savings from ramping it down, but to the extent you have to bring it up and down, there's some efficiency losses there.

But what NREL found by looking at all of these facilities all over the western part of the country was that the fuel savings are overwhelmingly greater than the cycling costs, by orders of several magnitudes. So this claim that the cycling costs are somehow going to negate the fuel savings just turns out, when you actually look at the data, not to be true. But it doesn't stop utilities from making that argument repeatedly. That's the point. That's why we need the change in the standards, is to make things more clear so that these debates cannot have to go on in such a protracted fashion.

One example, again, this is Golden Valley. I don't mean to beat up on them, but it's just our experience has been in fees negotiations with Golden Valley. We looked at their SRF filings for 2012 and 2013. They listed what appear to be all the costs associated with Eva Creek, but did not allocate integration costs. So as far as we can see, they're allocating zero dollars in integration costs to Eva Creek, and at the same time they're asking AEP to pay 7.7 cents or 6.9 cents in the fall and winter, which again are some of the periods when wind power is producing the bulk of its power.

So that seems on its face to be somewhat discriminatory. It would be helpful to have a better accounting of what they're charging themselves and what their actual costs are in order to determine whether the costs that they're asking us to pay, or my client to pay, are fair and nondiscriminatory. But just as a point of reference, the Fire Island wind facility is paying about 1.1 cents a kilowatt hour. So those numbers are very high for integration fees. Okay.

Contrary to the idea that we just talked about that the burden should be on the QF to ask the Commission to use this incremental approach, we think the utilities really should bear the burden of justifying the integration fees if they want to impose them for several reasons.

First is just the basic nondiscrimination requirement. That's a duty of the utility, is to be nondiscriminatory. The burden shouldn't be on the QF to prove that they're being discriminated against. It's the utility's obligation not to discriminate. So they should have the burden of proving that.

We've already talked about the risk. Because integration costs are kind of a judgment call more than a technical challenge, it's really a judgment challenge of what to allocate where, there's a risk of discriminatory allocation.

Another reason that the burden should be on the utility for justifying these fees is that there's no explicit FERC authorization for integration fees and none in the current RCA regulations either. There is -- by contrast, for incremental costs, there's a delineation of incremental costs and how they should be calculated and there are criteria. There's nothing for integration costs.

So the reason that FERC and states have been allowing these fees to be deducted is the utilities have been arguing that if you don't deduct for them, then you're really charging them more than the true incremental avoided costs. So in order to get to the true incremental costs, you have to deduct integration fees.

That may very well be true, but what we're saying is the utilities should be called upon to document that and to provide the data and the evidence that they're relying on to come up with these numbers and to be the ones to demonstrate why they think they're fair and why they affect the incremental avoided cost.

Since the overarching purpose of PURPA is to encourage cogeneration, again, it wouldn't be consistent with that to put the burden on the QFs. It really should be on utilities who are the subject of this law and who are the ones who the obligations are imposed on.

So we have come up with six criteria that we think are fairly straightforward and draw upon existing law. First is the nondiscrimination principle, which is pretty well established.

The second one for integration fees is that they could legitimately include costs reasonably necessary for safety, integrity, reliability, but then we want to rein that in somewhat with limitations. These are drawn from the types of fairness and reasonableness requirements that apply to interconnection costs; directly related to and necessary for the operation of the QF in excess of the corresponding costs the utility otherwise would incur, not duplicative of costs used for reasons other than integration of the QF, these should all really fall under the umbrella of just being fair and reasonable and nondiscriminatory.

Then No. 3 is similar. If you have one -- let's say you have one plant that is providing backup or standby power for more than one QF or for a QF and for a large generation source as reserve capacity or something, if you have that kind of a situation, we think the QF shouldn't be required to pay for it all. It should be subject to some kind of equitable allocation. So that's what that third criteria is getting at, is that if there are some efficiencies in being able to rely on one power source to back up multiple sources, then you should allocate them.

Similarly, no double counting. There are multiple calculations going on here. We have avoided costs. We have integration costs. We have interconnection costs. So some of the factors and criteria for each one are related to each other, and we could enter a situation where you're using the same figures and determining avoided costs and then that number gets calculated again in integration fees. So I think a criteria that you could apply to determine whether something's fair is to try to weed out those instances where there might be double counting.

The fifth one, this is based on some of the literature relating to renewable energy, that you don't want to create this kind of unfortunate incentive for utilities to sit back and do nothing and not take advantage of opportunities to reduce the integration fees that they could be charging. If there are things that they can do at a reasonable cost, like improving their dispatching procedures or putting a little work into wind forecasting or whatever, we're not talking about major capital enterprises. We're just talking about reasonable things that the utility could do to make sure that it's not overcharging for integration fees when it doesn't have to. That's what No. 5 is getting at.

And then No. 6 is just not

subsidizing the facility's other operations and facilities. You know, that would be completely contrary to the purpose of PURPA, which is to give the maximum incentive for this new and emerging industry and to give them the best price that you can. So asking them to pay for the utility's other resources would not be fair.

Okay. Moving on to curtailment. This is kind of a narrower issue. There's particular language in the FERC regulations. It's been more or less adopted into the state regulations. That's the language in the state regulations right there. It is not very well drafted. It's not all that clear on its face what it means, but that doesn't mean that it's open to interpretation.

The meaning is well established if you look at the FERC preamble to the order when it was adopting the regulation in the first place, and then every case in federal courts and in FERC interpreting that language since then have all said the same thing. That's that it was meant to protect QFs from rare situations involving the potential for negative avoided costs.

So the idea is when you're doing as-available pricing on a daily basis, you could have a low load scenario where the QF would go, uh-oh, if we provide you power today, we're going to have negative avoided costs, and we're going to have to pay you for taking our power. So that anomaly was a situation that was meant to be addressed by this (b)(1) exception.

So the case law has made it very clear, because a lot of utilities misinterpret this regulation. It's actually a pretty common problem. But it does not justify unilateral curtailment by utilities for economic reasons in terms of the utility possibly losing money. The idea is to protect the QF from losing money, or outside the context of realtime incremental avoided cost pricing.

This thing was never intended to apply when you're projecting incremental avoided cost over a long period of time in a fixed-rate contract or in some kind of annual rate setting or quarterly rate setting. It was only meant to be used when you could have these real short-term fluctuations that could cause problems for QFs.

So the debate in the briefs has been, well, our language is the same as the feds'. Why do we need to change anything? Why do we need any clarification of this? We're doing fine. So we have an example here in Alaska of the misinterpretation of this regulation leading to problems for a QF that's trying to get a project going and trying to get a power purchase agreement. In our negotiations with Golden Valley, they included language in a long-term contract that was contemplating either a long-term, fixed-rate pricing scheme or a variable scheme based on the quarterly prices that are set by the RCA, but never at any point were we talking about a daily or as-available pricing situation. So (b)(1) shouldn't have been applicable at all in that situation.

In the briefs filed by the Alaska Power Association and ML&P, they have agreed with us, and they are interpreting the language the same way and have said that this language is just not allowed to be in a long-term contract. But Golden Valley apparently, like other utilities around the country, misinterpreted the language and insisted on having it in there. We tried to get them to delete it; they wouldn't do it. They also included that same language that is very clearly not allowed in their proposed standard QF agreement that would have applied to all QFs that come to them and try to enter a power purchase agreement.

Another roadblock that we ran into was that we tried to get some guidance quickly through this informal complaint process that the RCA has. We were just asking for some simple advice to Golden Valley that this provision was unlawful and that they should take it out of their proposed contract. But the section apparently was uninformed about the actual meaning of Section (b)(1), and they told us that they found no violation of applicable law, even though it's pretty well established that this (b)(1) is not meant to be used the way they were using it. We've never heard anything otherwise, but Golden Valley is now of the mind that that provision was not really allowable.

But the biggest reason is that this has a chilling effect. The possibility that utilities can impose this kind of language on AEP or on other QFs and that they would really have to go to the mat and file a formal adjudication and go through appeals and litigation and all of that delay and cost scares people away and it scares projects away, and it takes things off the drawing board before they even get there.

In particular, this is a provision that would allow a utility whenever it in its own judgment decided it had economic reasons that it wanted to curtail your power, it could shut your power off and you would not have your only customer. Essentially that's the import of this provision, is that -- so the problem there is that a bank is never going to finance something when there is no certainty about this obligation to purchase the power under the contract even. You have a long-term contract, and even under the contract they could shut you off whenever they want. So this is a serious problem for getting projects going.

So this is our proposal. We're just drawing it straight from the FERC decisions. You can only use (b)(1) if you're in a realtime situation and you have this negative avoided cost problem. Then conversely (b)(1) shouldn't be incorporated into a long-term contract where avoided costs are not being determined in realtime. So we're just tracking what FERC has said and what FERC decisions are. I've seen other proposals for a shorter statement of clarification that might do the trick also, but I think some clarification is warranted.

Moving on to the next topic. This is the last of our four topics in our petition, as I mentioned and I think it's pretty clear. I think nobody -- after looking at it more closely and doing some research, nobody really thinks that Alaska is ready for competitive bidding or that it would even be a good idea in this kind of a market.

But some of the things that first attracted us to the idea of doing competitive bidding was that these laws on the books and the regulatory standards don't mean a whole lot if you're out there with these very powerful utilities trying to engage in negotiations, and they have access to the transmission and the distribution and they have much greater financial resources and they really just don't want the new kid on the block to come to their park, it's just -- it's really hard to make these regulatory standard work if there aren't good mechanisms for oversight and transparency and implementation.

So we're hoping to get those kinds of procedures established so that this all runs more smoothly for everyone. Some of the reasons that the oversight and transparency are needed are the long-recognized historical reluctance of utilities to open up their transmission systems to new players and new projects that would be run by independent producers.

There's also a well-recognized conflict of interest when you have -- on occasion utilities will have their own project competing with the proposed project. That was the situation that AEP faced when they were competing with Golden Valley in its Eva Creek project. So you had this conflict of interest of Golden Valley being the decision-maker and deciding between its own project and this independent project. So any time you have that kind of a situation, you have a potential for a conflict of interest.

Another issue is the control of the data. The vast majority of the data that's relevant for determining whether these PURPA obligations are being implemented relate to avoided costs and incremental costs and interconnection costs. All of the numbers and all of the data and all the graphs that would help you determine those numbers are in the hands of the utilities, which is not to say the QFs shouldn't have to turn over the relevant information that they have about their project, but the real determining factors of what the price is going to be are going to be in the hands of the utility. There currently aren't very good mechanisms for getting that information in a timely fashion and in a way that will help inform the negotiations. Then of course there's the bargaining card, which we've already talked about. So we think there are good reasons for doing something about getting better oversight and transparency.

So our proposal in this regard is an independent monitor and analytical report. I do want distinguish this from mediation in a traditional sense. We think of this as more of an investigation and a document review by a knowledgeable person who's independent and objective, who can really sift through all the material and get kind of a clear understanding early in the process of what would be reasonable in terms of avoided costs or incremental costs or interconnection costs and help the Commission understand that, so that they can exercise some oversight at an earlier stage in the process rather than waiting until the parties have been at each other's throats for a year or two negotiating and haven't been able to get anywhere, and then finally at their wit's end they come to the Commission with a formal adjudication, and then maybe it will finally get resolved.

This independent monitor can be the eyes and ears of the Commission and can be out there in the file room getting the information that you need and distilling it down and putting it in a report that is easy to read, both for the Commission and for the negotiating parties, so that they're all working from the same information. So that's the goal of this independent monitor.

Of course independence would be important, but we do recognize that there could be a limited pool of people who would be qualified to do this kind of work, so there's some flexibility there. If there's full disclosure of whatever conflicts there might be, the parties could waive it, and of course the person would need to have the sufficient experience and expertise to carry this out.

But I don't think this is that

unusual. In fact, independent monitors are used in a whole bunch of states, particularly the ones that are doing competitive bidding, but also other states. Commissions have relied on this kind of an independent monitor structure as a way of carrying out and fulfilling the regulatory standards.

COMMISSIONER PATCH: And can you identify for me the states where that's happening --

MS. CLEMMER: Yes.

COMMISSIONER PATCH: -- and identify for me as well whether or not they are under the auspices of the states' regulatory agency.

MS. CLEMMER: Yes.

COMMISSIONER PATCH: I don't need that right now. I'm sorry to interrupt your presentation.

MS. CLEMMER: That's okay.

COMMISSIONER PATCH: But I would like that at some time.

MS. CLEMMER: Thank you. I had it listed in my notes. It's also in our brief. I'm sorry, I'm not finding the right page.

COMMISSIONER PATCH: Very well. If it's in your brief, I'll take it upon myself.

MS. CLEMMER: Okay. It's in our brief.

COMMISSIONER PATCH: Does your brief also disclose who pays for this --

MS. CLEMMER: Yes.

COMMISSIONER PATCH: -- since the -- wonderful. I'll look forward to rereading your brief. I'm sorry I missed it.

MS. CLEMMER: That's okay. I should correct myself. The brief lists the states where the independent monitors are used, and that same report that discusses the states that are using independent monitors indicates that in nearly all states the costs are borne by the utility. That's their general statement, but they didn't go state by state and say exactly who's paying what. But they did say nearly all states, so I would assume that the ones they used as examples would be included.

COMMISSIONER PATCH: Thank you.

Depending on when this hearing concludes today, that will be a first effort I make. Thank you.

MS. CLEMMER: Okay.

So the independent monitor responsibilities. I kind of described those already. Reviewing the utility documents and the data. We do want this to be a mutually, you know, full disclosure. The QFs would also be required to share their information about the design and operation of their facility. Obviously the monitor couldn't decide what's fair and reasonable without knowing everything about the proposed facility.

But at the same time PURPA exempts QFs -- as part of their purpose of encouraging these small facilities and reducing regulatory barriers, it exempts them from having to provide their financial and cost information. But that really isn't relevant to what the utility's avoided costs and incremental costs would be anyway.

The independent monitor could request additional information. Then the ultimate culmination of this whole thing would be the report that they prepare, which is, in our view anyway, intended to provide transparency and to let the negotiating parties really be informed of each other's real justifications for their positions and not just kind of throw proposals back and forth without really providing the backup data.

The Commission would be involved to a large extent in kind of scoping out the tasks of the independent monitor at the outset. They can read the reports and identify gaps, ask for additional analysis. Depending on what the reports say, they can kind of point the parties in a direction that might get them to come to agreement, or they might ask one of the parties whether they'd be willing to modify their position and, you know, kind of make a recommendation in a particular direction.

We're not suggesting that this would be binding in any way. If the party didn't take the recommendation, they could certainly pursue a formal adjudication, but at least the dialogue would start earlier in the process, and there would be a mechanism for preventing things from having to go to kind of a litigation, adversarial stance that could take a lot of time and resources.

So as I mentioned, that report that I was discussing was EPSA. In that report they indicated that almost all states impose the costs on the utilities, and so that's what we're proposing here also. We think there are a lot of good reasons for that. You know, they're listed there: The data, the conflict of interest, the bargaining position. The financial resources is a big one. By definition QFs are small and they're new, and they're trying to generate projects that will give them an income stream, but they're in the early stages oftentimes. You know, so they just would have a much harder time bearing these costs. Also, this type of thing, every cost can serve as a barrier to the development of these projects, which is contrary to the purpose of the law.

I'm moving along pretty well

here. I just wanted to throw in a few comments and to end on a note that there is a lot of positive energy here in Alaska to be excited about. We have world-class renewable energy resources in a lot of different areas. This is map of hydro, but you can see something similar for geothermal and wave and kinetic and tidal and river currents. You know, just pretty much every type of renewable energy there is. We have the most of it or almost the most of it of anywhere else in the country.

So we have this incredible potential in this state, and I think changing these rules and kind of restructuring the framework that these negotiations happen under can really start to unleash some of those projects that will start developing this potential.

Wind, of course, is our special interest. Alaska has been referred to frequently as the Saudi Arabia of wind. You can see from the map there's just wind everywhere you look. The wind that my client is experienced with has been having a pretty good couple months here, which should be exciting, just in general in terms of what we can really do if we start working on this in a more concerted way.

I don't know if people are that familiar with these charts, but this is wind production data. So you'll see basically three take-home points from looking at these graphs. This is December. First of all, you see long stretches where you have production over 3,000 kilowatt hours a day. Five days, five days, seven days, and here in January you have 17 days straight of really high production.

Another thing to look at are the long strings of days when you have 24 hours, or close to 24 hours of being available at 100 percent. That means you're not having shutdowns. You're not having excessive wind that can cause the facility to shut down automatically to protect itself. You are in the sweet spot for 17 days at a time of near maximum capacity. So you're producing as much wind power as you possibly can, but at the same time not going so extreme as to trip the system and cause problems.

So these successes are really doing a service to the Fairbanks community. They're displacing a lot of oil. I think we calculated just in these two months alone displacing 89,000 barrels of oil -- or gallons of oil.

Another aspect of this is that when you have wind power that's this steady for these long stretches of time, you're really providing energy security in a grid that is fragile, as people know. This particular facility is in Delta Junction, and it is not dependent on the Alaska intertie or the northern intertie. So if there's a problem on either of those systems, there's an earthquake or if there's just a failure, transmission failure, avalanche, Delta Junction can keep producing power and can keep the lights on in Delta Junction and in Fairbanks and in some of the industrial facilities along the way, depending on how much they use.

It happens to be in a particular part of the grid where there is redundancy, which is a good thing, and there isn't always in a lot of areas of the railbelt. So we have redundancy, and we have no problem with relying on the intertie.

So this wind power is just very helpful, I think, to the Fairbanks community who can get stranded easily by a variety of different circumstances. So if this is what we can do, or what AEP can do with just two turbines, two of their big turbines running, imagine what they could do with 16 turbines and what other facilities could do with similar resources. The map showed there's a lot of wind in this state, and probably a lot of it has similar characteristics.

So we think these rules could be really helpful in getting some of those projects off the ground. It's actually your turn to go ahead, except I wanted to summarize.

MR. CRAFT: I just want to make one point about this particular chart you're looking at. If you look at the 26th and the 27th of January, you'll see 20,523 hours, 20,336 hours on the one turbine, and on the other side you're looking at, I believe that's Turbine B, at 20,630. Just so you can get a reference point of what that really means, we are running 900-kilowatt turbines; 900 times 24 is 21,600. So the most energy you could make in a day is 21,600 kilowatt hours.

So when you see events that are -- like from the 25th through the 27th, for example, that's a pretty strong wind event. The 26th and the 27th was 48 consecutive hours of 98 percent capacity. It's a pretty unique wind regime. I just wanted you to get an idea of what those numbers really mean. You see a lot of 18s, 19s, 17s. We're looking at about a 51 percent capacity factor is what we had in December. January is going to be somewhere in the 54 percent capacity factor overall.

MS. CLEMMER: I was going to also add that this is not a fluke. This is not just two crazy months that are unusual. Mike has told me that this pattern are steady, multi-day wind events, which are unheard of in the wind industry in general. These really long periods of steady winds are typical of this area and are documented back to the 1950s. So this is just one of the things that Alaska is blessed with, is these mountain passes where the wind just funnels in a certain direction and you can really rely on it. So I think wherever you can find other spots like this, I think would be good.

I just wanted to do a quick summary. You have this summary sheet in front of you. This is a summary of our proposals. A couple of things we're asking for are we think legally required under PURPA and the FERC regulations implementing it.

Incremental avoided cost, the QF options for being able to use an LEO, and also to control the timing of when the avoided cost determination is made. Then the application of the avoided cost factors to firm and nonfirm power. Those are the changes that we think are really required.

The second category would be the changes needed for clarification. Integration fees is a hot area of dispute. It would be really helpful to have some criteria to establish the rules of the road for utilities and QFs in this area. We think, very importantly, the burden should be on the utilities to justify the deductions they want to make from what would otherwise be required in terms of incremental avoided costs.

Curtailment. Again, this is not unique to Alaska, that utilities are trying to incorporate these (b)(1) provisions giving them kind of carte blanche to curtail when they want to in long-term contracts. So we think there's some clarification that's needed there, despite the fact that the regs are more or less consistent with the FERC regs.

Then, finally, the independent monitor and the transparency we think are important to make these other changes work in practice and to get the negotiations moving along more smoothly and getting this out of a contentious realm as much as possible.

So thank you very much for your attention.

ALJ ROYCE: Thank you.

Mr. Craft, as managing partner of AEP, would you like to make any additional comments?

MR. CRAFT: Yes, sir. Mike craft again.

I'd just like to point out that I'm a little out of my element here. I'm a builder, and I've been very lucky to be able to work on the projects I've wanted to work on for the last 35 years in Alaska. You know, I got to a point where I saw the economy faltering in Alaska. About eight years ago I saw it coming.

I also heard the rhetoric out there from the federal government, from the state government, from local government, from the utilities, from my neighbors about developing alternatives. A lot of it came from energy security issues. A lot of it came from just how high the energy costs were. Certainly in Fairbanks a lot of it came from some pollution issues that we're dealing with.

So I guess I was a little naive, because I really felt that there was a calling out there. There was a calling for people to step forward that would be willing to do the work and put the effort in to create these kinds of opportunities. Sadly, I found out almost I guess at the point of no return, where I didn't have enough gas to get back home; I had to go all the way to the end before I realized how difficult this was going to be.

I certainly never anticipated having to be involving this many people and taking up so much time to get to the point to where I would be able to continue to finish my project. It really was about doing something positive for my community. It had ancillary effects of better air quality, cleaner water, of lots of jobs, economic opportunities for people that want to put their time and effort into projects like this.

I really want to apologize, because I don't know if I would have done this if I had realized then what it was going to take to build a couple of wind turbines and do something about our problems in our community. At the same time I feel kind of honored now, because I'm solving a much larger problem than what's just happening in Fairbanks, and I didn't realize that was going to be part of this. But this is our state's problem. It's happening everywhere. I guess now, eight years later, I'm a little better informed about what these problems really look like, and we're staring this one in the face today.

I appreciate the opportunity to put that on the table with you guys. Thank you.

ALJ ROYCE: Thank you, Mr. Craft.

It's time -- we've been going over an hour. Why don't we take our midmorning break, just take a short ten-minute break. So we're back here at ten to 11:00. Thank you.

(Off record.)

ALJ ROYCE: Thank you. We're back on record for the continuation of the public hearing in Docket R-13-002 at approximately ten to 11:00 a.m.

At this time we'll turn to

Commissioner inquiry. Do any of the Commissioners have questions?

COMMISSIONER PATCH: I think I have an obligation to thank Ms. Clemmer for a handwritten document that I -- for those people that can't see it because your eyes are like mine, it is a listing of states where independent monitors are apparently accepted protocol. The listing of states is Arizona, California, Maryland, Georgia, Colorado and Oklahoma. Thank you very much, Ms. Clemmer.

When you passed across materials on your slide No. 13, you observed that you have experience with specific instances in Alaska where QFs or IPPs have suffered. Is that reference statement with regard to your clients suffering, or is that with respect to another QF or another IPP with which you have some acquaintance?

MS. CLEMMER: I was -- if I said I, I meant my client. I'm sorry if I misspoke.

COMMISSIONER PATCH: Well, Mr. Craft, let me address the question to you then.

MR. CRAFT: Yes, sir.

COMMISSIONER PATCH: Is that -- I'm well aware that there has been ongoing negotiation with --

MR. CRAFT: Well, I'll give you one -- the biggest example I can think of. When we were determining whether this was appropriate action for us to take to develop a renewable resource, one of the things we considered was the tax implications. At the time the federal government through the Stimulus Act had initiated the -- what they call the 1603 credit. That 1603 credit was put out there basically to entice developers to get into the renewable energy market.

If you were successful at qualifying for it, you were entitled to a 30 percent capital reimbursement. In a lot of cases that 30 percent capital reimbursement would act as your percentage of ownership in a project. So, for example, with our project, it was $54 million. We would have been able to pay off 30 percent of that capital right away with the 1603 capital reimbursement grant.

That has since left, so our project is now handicapped in that sense. Then after that happened, we also experienced the same thing with the production tax credit, because that has also lapsed. So we lost out on those two opportunities.

One of the other major issues that happened to my company was that under this 2-megawatt limitation, we were limited to the equipment that we could use, okay. So instead of being able to go with Turbine A or Turbine B, we would have to go with a different piece of equipment that may not be as applicable to that wind regime. It also wasn't as well-known equipment, wasn't developed in the cold gray environment and so on.

So it forced my company to have to develop relationships with turbine manufacturers that hadn't worked in an arctic environment. So as a consequence, the first year and a half of operating the EWT turbine, the first one we put up, was pretty sad, because these guys really -- their idea of cold was about 25 degrees Fahrenheit. When they showed up at minus 35 with their tennis shoes on -- you know, it was those kinds of problems.

So it handicapped my company, because it also -- it gave a bad taste in the mouth for people that were looking at renewable energy projects, because here you have this project that's supposed to do X. You know, we were looking at a 30 percent capacity factor, but yet we were having problems with the equipment, getting it to work. So instead of having a capacity factor that we could brag about like we did today, for example, we had to keep our mouth shut and basically just try to work through it.

COMMISSIONER PATCH: So your direct knowledge of instances where QFs or IPPs may have suffered is with respect to your AEP project.

MR. CRAFT: Well, CIRI as well.

COMMISSIONER PATCH: Well, we'll deal with CIRI when CIRI comes to the table.

MR. CRAFT: Well, you asked me of the ones I knew of, and those are the two projects that I've seen handicapped by this issue.

COMMISSIONER PATCH: Thank you very much. And in your conversations with GVEA regarding what Ms. Clemmer referred to as models for the calculation of incremental avoided cost, did you specifically ever discuss a particular model or a range of models in your dealings with GVEA?

MR. CRAFT: Yes, sir.

COMMISSIONER PATCH: And which particular model did you discuss with GVEA?

MR. CRAFT: Well, initially I came forward with a model of 12.5 cents a kilowatt hour for the power. That was the initial offering that I made to them. Then several years later, after we had problems getting that to float --

MS. CLEMMER: Because he's talking about the fixed --

COMMISSIONER PATCH: The actual costs, yes.

MS. CLEMMER: Right. We never really attempted to do an incremental of what it cost calculation because that's not what the regulatory standard currently is.

COMMISSIONER PATCH: I understand, but you referenced in your presentation a spectrum of models, and I was curious -- and I'm aware of some of them.

MR. CRAFT: We offered them -- we offered --

COMMISSIONER PATCH: Just a minute. I'll come back to you, Mr. Craft.

MS. CLEMMER: Okay. The model that we -- and there's kind of two questions in there. The model that we referred to in our discussions with Golden Valley was their internal production cost model, which they summarized for us and described in fairly general terms, but they never provided us with the underlying data or the assumptions or their actual methodology. They just kind of provided a list of some of the criteria that they looked at, and then they came up with this number for -- actually that was partly for integration fees, but any of the modeling that was done was done by Golden Valley.

But then the second question is

what other models are out there that we're aware of. I've read, just in reviewing the literature, about a number of different models that are used. They're summarized fairly well in Carolyn Elefant's -- one of the papers that she's written --

COMMISSIONER PATCH: Yes.

MS. CLEMMER: -- so she might be able to answer some questions about that.

COMMISSIONER PATCH: All right.

Now, Mr. Craft.

MR. CRAFT: Yes, sir.

COMMISSIONER PATCH: I interrupted you.

MR. CRAFT: No problem, sir.

COMMISSIONER PATCH: I know I did that.

MR. CRAFT: No problem, sir.

COMMISSIONER PATCH: I don't do it to be rude, but I wish to keep track of the conversation, and it's difficult for an old man to have more than one at a time.

What do you have to tell me?

MR. CRAFT: Yes, sir. The last offer that we made to Golden Valley, and when you talk about a model, was the average avoided cost now model. We came to them after we found out that we really weren't going to move forward with a different kind of contract, so we focused on the contract that we felt at the time was legally applicable, and that was the average avoided cost calculation.

We asked them for a contract for 25 megawatts of capacity at their average avoided cost calculation. What we got back from them was this 9.8 cents offer, which was under the average avoided cost by 2-plus cents. They were requiring 7 to 8 cents in regulation cost. So that was the answer to that model that we proposed.

COMMISSIONER PATCH: Thank you, Mr. Craft. I have no further questions. I thank you very much, and I appreciate the handwritten document you've provided. I'll share it with the other Commissioners.

MS. CLEMMER: Okay. Thank you very much.

ALJ ROYCE: Okay. Thank you, Ms. Clemmer and Mr. Craft for your

presentations.
At this time we'll now turn to Carolyn Elefant. Are you on the phone?
MS. ELEFANT: Yes, I am. I was just unmuting.
ALJ ROYCE: Okay. Can you please spell your name and identify yourself for the record?
MS. ELEFANT: Sure. Sure. My name is Carolyn Elefant. It's spelled C-a-r-o-l-y-n E-l-e-f-a-n-t. I am an attorney in Washington, D.C. with my own firm. I represent AIPPA, the Alaska Independent Power Producers, in this proceeding.
ALJ ROYCE: Thank you, Ms. Elefant. You can proceed with your comments.
MS. ELEFANT: Okay. Before I begin is the voice -- is the level of volume working out for you in the hearing room?
ALJ ROYCE: We can hear you loud and clear.
MS. ELEFANT: Okay. That's what I was afraid of. Anyway, thank you.

AIPPA and its members thank the Commission very much for this opportunity to participate at this public hearing, and also for opening this docket on these very important regulations. As I'm going to discuss today in my presentation, the revisions that have been proposed to the Commission's regulations on PURPA are really important in order to bring the regulations into compliance with federal law and also to foster development of paying alternative energy supplies that in the long run will have the effect of reducing rates for consumers.

So before I get to the substance of my comments, I just wanted to give a little bit of background on AIPPA. AIPPA is a statewide association of independent power companies who are engaged in development of different types of renewable and alternative energy sources. These include combined heat and power, wind, conventional hydro, and also marine hydrokinetic. These technologies collectively diversify Alaska's energy portfolio, they reduce energy costs, and they also create jobs within the state.

But in spite of the commitment of AIPPA's members to clean energy production, current regulatory policy, as you've already heard, has made it very difficult for independent power producers to fully participate in electric markets. Ultimately in the long run it's to the detriment of the state and also consumers who will bear higher costs.

So I don't really want to repeat AEP's presentation. It was quite extensive. AIPPA's comments and our position is consistent with much of what AEP has presented already. As you know, we've also submitted extensive comments and also reply comments, so I'd like to avoid repeating them here.

One thing I wanted to do at the outset is testify to some of the broader themes that the Commission will hopefully keep in mind as it reviews our comments to make sense of all of the information that's nitty-gritty in this proceeding.

So our first theme here is

urgency. The Commission's current regulations don't conform with the Public Utility Regulatory Act of 1978, and really they've been noncompliant for almost three decades. As you've already heard, the Commission's regulations -- the definition of avoided cost departs from the federal definition adopted by FERC and PURPA, and also the regulations don't guarantee QFs a legally enforceable right to sell power.

Under the current system with the average system costs, consumers of independent power producers have been underpaid for power over the past few years, and the regulations as currently drafted also don't protect independent power producers from discriminatory practices. It's really essential that the Commission act swiftly at this time to bring the regulations into compliance with PURPA. So that is really the first thing that we believe is most important in this proceeding, is the urgency.

The second theme is simplicity. We've really tried very hard to keep this proceeding simple. One of the utility comments that we've noticed is that they have tried to unnecessarily complicate it or delay the proceeding by proposing technical working groups, by arguing that calculations of avoided cost is very complex. But as AEP has already explained, the underlying legal principles in this proceeding, for example, the definition of avoided cost under PURPA, other concepts like nondiscrimination, stability, and transparency are just not that complicated. So we'd like the Commission to focus on keeping this simple.

The other thing that AIPPA -- the other approach that AIPPA has taken to further keep things simple is that we've recommended that the Commission where possible simply adopt regulations and policies already used by FERC. That way the Commission can borrow from an already established body of law. Of course the Commission has the ability to depart from federal law and from the FERC regulations where it sees fit or where necessary to accommodate the unique interests of the state, but one of the ways to keep these proceedings simple is to already use an approach that's in place that comes with a built-in body of -- a built-in regulatory framework.

So once this framework is in place, AIPPA expects that many of the problems that producers have experienced will be addressed just by putting this legal framework in place, and that many producers will be able to reach their goals through the negotiation process. But it's really important to again revise the regulations and bring them into compliance so the appropriate framework is in place.

Now, simplicity is also important for another reason, and that's stability. In order to attract investment to the independent power producer market, there needs to be certainty for investors. They need to know how the system is going to work. So the ability to reference how the process -- how the FERC process has worked in the past is something that will help -- that will appeal to investors. Also simple rules also are very helpful because it makes clear -- it makes expectations very clear. So by having simple rules in place that are understandable and transparent, it will help attract investment and avoid delay and hopefully avoid some of the problems that we've heard described by AEP.

Another theme that we hope comes through our comments is this idea of fairness. AIPPA and its members are not seeking preferential treatment. As one of the utilities, I believe it was ML&P said in their comments, policy should be structured in a way that they don't overly incentivize independent power production, but neither should they discourage it. That's very consistent with this approach that AIPPA has taken.

We really believe that the system should be fair and should achieve a level playing field. That's what was Congress' intent in enacting PURPA. It was to encourage independent power development, but not to impose the burden on consumers. It was a very ratepayer neutral approach to developing independent power, and it wasn't supposed to come at the cost of utilities or at the cost of consumers. So that's the approach that we are endorsing here.

So at the same time -- and this is something that AEP had mentioned in terms of fairness. In order for this system to operate fairly, AIPPA should not have to negotiate for rights that are already guaranteed by law. One of the arguments the utilities have made is that the current regulations allow for independent power producers to request specific practices -- specific pricing mechanisms on a case-by-case basis. But the problem there is that AIPPA members should not have to negotiate for something that they're already entitled to. So in order to create a system that's fair, the Commission should put in place regulations that are consistent with PURPA so that everybody is starting from the appropriate place.

The fifth theme, finally, is transparency. Rates should not be set in a black box. They should not be set on data -- they shouldn't be set in a black box.

Utilities should provide information that substantiates their rates. They should make all of the data available so that it can be reviewed by the other parties in this proceeding.

Many of the disputes that have arisen in some of these previous negotiations arose simply because there was a lack of verifiable data. Essentially when utilities are going -- if they're going to calculate avoided cost or integration charges, they really should make available the data that supports their positions.

So, again, those are sort of the five very broad themes that we have -- that are brought out in our comments and that weave their way through the testimony that I am going to give today.

So we've already heard from AEP a little bit of background on PURPA. I'll just add a little bit more, but I won't go into that much more detail. It was a statute that was enacted in 1978. Essentially what it was intended to do was to break up the utility monopoly on the market and encourage new power generation at a time when there was an energy crisis and when there was a lot of concern about future energy security. That's the context that PURPA has been adopted within.

Now, Congress has revisited PURPA on several occasions in the past 30 years. Many times Congress has had an opportunity to repeal PURPA. There are many opponents of PURPA. Many do not like that particular PURPA structure, but every time Congress has left the provision -- has left PURPA intact. Even in 2005 with the Energy Policy Act of 2005, Congress to some degree cut back the mandatory purchase obligation and found that in markets that are robust and competitive with lots of options, a mandatory purchase requirement of PURPA may not be as important. But very significantly they did not eliminate that obligation entirely. So even as recently as 2005, there's evidence that Congress still believes that there's a need for regulatory policy to encourage independent power production.

The other component of PURPA that

I think is really important is that it's a statute that is intended to be ratepayer neutral. Again, very clearly throughout PURPA you see that PURPA wanted to open up markets, but it did not want to unfairly burden ratepayers with the cost of doing so. So that's another theme that I think AEP also highlighted very effectively.

In any event, after PURPA was adopted, FERC enacted regulations as it was directed to by the statute. It enacted regulations to implement PURPA. Essentially the way that the system works is that FERC regulations would create sort of a framework for a structure, a uniform structure that would govern what was happening in all 50 states. But FERC still allowed the states sufficient flexibility to modify or adopt PURPA in such a way as to meet the unique needs of those particular markets.

So you see in the FERC regulations, for example, a list of different factors that states can consider in setting avoided costs. They're not required, but these are things that can be taken into account. That's in order to give states sufficient flexibility to enact the statute in a way that works best for the indigenous power producers within the state and also for their ratepayers.

So I'm going to also address the four different topics on which the Commission sought comments.

The first is avoided cost. As we've already heard from AEP, FERC defined avoided cost as incremental cost. Again, as AEP mentioned, FERC expressly rejected the idea of basing avoided cost on average cost pricing. FERC believed that average cost pricing would not fully compensate independent producers for the cost of power, and for that reason it selected the incremental cost methodology.

That is really very consistent with the whole way that -- you know, that utilities engage in planning. Customers are always paying for the next unit of power. Also, this idea of paying for the next unit of power, I think, is very consistent with another ratemaking principle, which matches benefits to burden. Customers are expected to pay for what they use. The burden of paying rates is imposed on customers, and they derive some type of a benefit. I think that incremental pricing, this idea of paying for the next unit, is something that more closely aligns benefits and burden.

That's sort of another point that I'd just like to make as an aside. Even though PURPA talks about, you know, incremental cost pricing, PURPA also includes -- under PURPA, rates have to be just and reasonable and nondiscriminatory. So even though PURPA involves this incremental cost pricing approach, much of PURPA also still embraces ordinary, routine components of ratemaking that the Commission is well familiar with; just and reasonable rates matching benefits to burden. So we're not asking for any of that to be ignored. That's all part of the PURPA ratemaking process.

So AIPPA has participated in a couple of proceedings before where this issue of incremental versus average cost pricing has come up. As we mention this in our comments, AIPPA has previously stated that the system average method consistently undervalues energy purchased from qualified facilities and small power producers. System average costs put QFs and small power producers at an economic disadvantage, and it's not in the public interest.

As we also noted in our comments, when Commission staff considered AIPPA's comments, these were comments that were filed April 2nd, 2012, staff actually agreed that under the currently employed average cost methodology, the resulting rate runs the risk of being not truly representative of the actual costs avoided by the QF producer.

So this is something where I think there's already some growing acknowledgment that average costs really don't fully compensate for the costs that the utility is avoiding.

So really one of the most important revisions that the Commission should make is to add the term "incremental" to the definition of avoided cost pricing.

Again, it's for the reasons that AEP explained and that I alluded to before. It's not enough for QFs to have to ask -- approach the Commission and propose incremental cost pricing. Incremental cost pricing has to be the starting point. It isn't a point that QFs have to argue their way up to in order to achieve it.

So really the regulations need to be changed so that everybody is on the same page and that incremental avoided cost pricing serves as a starting point for negotiations. Once you have that as the floor, again, the parties can negotiate higher than avoided costs or lower than avoided costs. We don't want to eliminate the opportunity for parties to negotiate and to enter into contracts, but at the same time there has to be an agreed-upon starting point, and that incremental avoided cost pricing would be the agreed-upon starting point.

So in addition to the definition of avoided cost, we've also suggested in our comments, and AEP discussed this as well, the regulations also have to make clear that QFs have the option to provide power either on an as-available basis or pursuant to a legally enforceable obligation.

The legally enforceable obligation is really what gives PURPA its teeth. In Order 69 where FERC adopted its own PURPA regulations, FERC said that the legally enforceable obligations permit -- it discourages utilities from trying to circumvent their PURPA obligation. A utility can't try to avoid entering into a contract or prolonging contract negotiations in order to get around its PURPA obligation. So that's why the obligation is very important.

The legally enforceable -- just by making clear that QFs have -- that PURPA confers a legally enforceable obligation can really increase their leverage in negotiating a power purchase agreement, and it can also help avoid an impasse where, for example, a utility insists on contractual provisions that are inconsistent with PURPA and, you know, basically offers a take it or leave it deal. There's a legally enforceable obligation to enter into a contract. That prevents a utility from just walking away.

So by just using the same language that the Commission -- that FERC uses and establishing a legally enforceable obligation would be very useful in helping to give independent power producers -- to leveling the playing field for them during negotiations.

Finally, another change that the Commission should make in its regulations relating to avoided cost and the enforceable obligation is that the Commission should make clear that the utilities adequately disclose the data, information, and methodologies that they use to calculate avoided cost rates. That would also be a very important theme including the transparency of the process, which again is another one of the themes that AIPPA believes is important in this proceeding. So those are essentially our comments on avoided cost.

In terms of the details, we have suggested that the Commission -- that this Commission simply adopt FERC's regulations on the factors to be considered in avoided cost ratemaking. We discussed this in our comments. It's a somewhat lengthy list and we don't need to go into it here, but we believe that that would really give sufficient flexibility to this Commission to set avoided cost rates. Again, it's a system that is very well known. It's been applied -- the factors have been applied before, so they're very familiar and so it could be adopted very easily.

The next topic that I'm going to discuss are integration costs. AIPPA considers a -- to some extent there can sometimes be a little bit of confusion about what integration costs entail. When we talked about integration costs in our comments, we considered them to be the costs associated with maintaining reliability while integrating renewables into the grid. Those are the costs that we would consider to be the integration charges. We view these charges as a little bit different from interconnection costs, which typically refer to actual hardware and physical facilities that are needed to bring renewables online and deliver power to the grid.

Traditionally, those interconnection costs are treated a little bit differently. They're sort of treated to some extent outside of the avoided cost rates.

So one of the things that AIPPA has noticed is that in some instances utilities have been proposing integration charges that may account for a large portion of the overall project costs. There's two problems with that. Sometimes when the costs are -- these costs are proposed, they're just unsubstantiated. That's very problematic because when integration charges aren't substantiated, it's not clear whether they're costs that are attributable to independent power, if they're costs that relate to upgrade to the entire system, in which case all system users should pay for them.

So without substantiation of integration costs, you can't tell if you're matching the burden with the benefit. You can't tell whether those are aligned. Again, that's another point that I had made earlier. Matching the benefits received from particular policies to the burden of the cost is just a generally accepted ratemaking facet. Unless your integration costs are substantiated and you can see what's causing them and how significant they are and what they relate to, you really can't decide how to allocate them. So that's one reason why substantiating integration costs is so very important.

The next point that AIPPA has made is that when utilities bring their own facilities online, they typically don't charge integration costs themselves, so charging integration costs to other users is also discriminatory.

So what's the solution? At this point there are so few systems online already. The penetration of renewables is so low that at this point AIPPA believes that there should at least be a presumption that integration costs are zero unless a utility can demonstrate otherwise. The benefit of establishing this type of presumption is that it ensures that the onus remains on the utility to provide legitimate and verifiable data on integration costs that can directly be linked to an integration to the grid. So that's the approach that we have taken in our comments.

AIPPA also believes that to the extent that the Commission authorizes recovery of integration charges from QFs, those costs should be no more or less than what the utilities would allocate towards the operational costs of its own facilities. So that part of the approach also ensures that the charges are nondiscriminatory and that they can remain neutral. So that's the approach that we have proposed for integration costs.

Again, keeping it simple, keeping it consistent with generally applicable ratemaking practices of matching benefits to burden and ensuring that there's fairness and a level playing field for QFs and for utilities.

The next point that the Commission sought comments on is curtailment.

I think that AEP covered a lot of the issues and concerns very thoroughly. The concern, of course, with unilateral curtailment is it offers utilities another opportunity to potentially circumvent PURPA. You know, to curtail power at a time when it's economically convenient for the utility to do so is really just a way for the utility to potentially circumvent the PURPA obligation. Especially if a utility has a long-term contract in effect with a QF that already provides pricing, as FERC said, the long-term contract already takes into account the general ups and downs and the economics of the power purchase agreements.

So that's one of the concerns that curtailment raises. FERC has dealt with the curtailment issue multiple times, including in some recent cases that both AEP and AIPPA and some of the other parties have cited. FERC emphasizes that they're not -- that they're intended to be applied in very narrow circumstances.

We noticed as we reviewed the utilities' comments that there really does seem to be a general consensus between all of the parties that curtailment should be approached very narrowly, that projects should really only be curtailed if there are some emergencies or in very narrow situations that have been discussed by the FERC rules and that AEP also elaborated on.

So the proposal -- so what we've suggested that the Commission do in this situation to address curtailment is currently the Commission's regulations on curtailment basically track FERC's regulation. So AIPPA does not believe that there's really any need for the Commission to change its regulations on curtailment. But we do think that as part of this proceeding, the Commission should perhaps adopt prefatory language in the preamble essentially stating something to the effect that curtailment regulations are not intended to allow a utility to escape its contractual or legally enforceable obligation to purchase power from a qualifying facility. That should only be used in emergency circumstances and otherwise unilateral curtailment should be avoided.

We believe that by making this type of a statement, again, the Commission will sort of clarify the starting point so that everybody can start in the same place and that when parties go to negotiate a contract, if a utility has some sort of broad provision within the contract for allowing unilateral curtailment, it will be very clear that that type of provision is a nonstarter. We think that having that type of clarifying language will really go a long way to avoiding an impasse in negotiations and avoiding different disputes in the negotiation process.

In terms of the competitive bidding practices, at this time AIPPA believes that really discussing competitive bidding is premature as markets are still too nascent. In terms of other alternatives, like alternative dispute resolution and market monitors, these are policies that may be worth exploring, but AIPPA would suggest that these different policies perhaps be decided outside of this docket.

Those types of proceedings could

be much more involved, and they might require more discussion. Again, that would -- could cause undue delay in a proceeding where it really is urgent for the Commission to rectify some of the problems of the regulations right away. So while we're not averse to exploring those different options, we believe it could be handled outside of this particular docket and doesn't necessarily have to be addressed at this time through workshops or other extensive review processes.

One last point that we had raised in our -- in the AIPPA comments that goes to the question of the Commission's jurisdiction in this proceeding, as the Commission is well aware, there are some publicly-owned or municipal utilities that are not subject to the Commission's jurisdiction. So even though those municipalities are subject to PURPA, they are required to purchase -- to have avoided cost rates available and to extend and to purchase power from independent producers. That's something that is really enforced through the FERC process; however, even though the Commission doesn't have jurisdiction over those entities, if the Commission were to adopt regulations that are consistent with what FERC is doing, it would sort of ensure uniformity across the board.

So that would be another reason for the Commission to adopt FERC's regulations, because it would ensure that what the municipal systems are doing in terms of PURPA were very consistent with what the privately-owned utilities are doing. They would generally be subject to the same regulations, even though the regulations that are -- even though the course of action for enforcing the regulations against the municipalities would have to be taken up through the FERC enforcement process.

So those are really the -- it summarizes the points that we've already made in the comments that we've submitted. Just to conclude, again, as AEP has already pointed out, Alaska has an abundance of renewable resources, but at the same time many of those resources are not being developed. Also, Alaska has some of the highest energy rates in the country. PURPA affords a mechanism that can help to address many of Alaska's energy problems, but in order for PURPA to work, the Commission should implement this in a way that is consistent with the governing statute, and that unfortunately has not been the case.

This proceeding provides the Commission with an opportunity to get PURPA right and to send out the types of signals that are necessary to stimulate independent power development within Alaska's markets. By implementing -- by conforming the existing Commission regulations to FERC regulations and to PURPA, the Commission can bring the type of fairness, transparency, and stability to Alaska's energy markets that will attract independent power and promote competition, which ultimately will benefit consumers and ratepayers.

Again, thank you very much for the opportunity to participate and to offer comments at this hearing. I'm happy to answer whatever questions the Commission may have.

ALJ ROYCE: Thank you, Ms. Elefant. Are there any questions by Commissioners? Commissioner Rokeberg.

COMMISSIONER ROKEBERG: Thank you. I'm curious, Ms. Elefant, if you have an opinion about the FERC versus Idaho case. Is it your understanding that -- I'm not that familiar with the final details of it. I just know that there was a settlement. But can an IPP and a utility enter into the bargaining of the terms of a contract even though an LEO is now presumed to be in place given that case, just so they're in conformance with the particular state's regulations?

MS. ELEFANT: Let me see. So as you pointed out, the case -- the FERC versus Idaho case has been settled. My view of that case is always that it -- well, first of all, just by way of background, it's very, very unusual for FERC to bring an enforcement action against a state Commission. In fact, this was the first time FERC had ever done that. I think that the only reason that FERC actually brought the action was because there had been some disagreements between FERC and the Idaho Commission over when this legally enforceable obligation attached.

So what had happened in Idaho, Idaho had originally had a standard offer rate that was available to projects up to 10 megawatts. Idaho eventually decided to downgrade that standard offer to projects with just 100 kilowatts. So in that interim period, there were a couple of facilities that were 10 megawatts or larger that were sort of on the verge of entering into a contract. So obviously they wanted to be able to keep the standard offer rate, which was very favorable.

The utilities in turn were eager to move on to the new system where there would be a different rate in place for these 10-megawatt facilities. So as a result, the negotiations dragged out and the companies -- and so they dragged out. The Commission did not approve the contract. They found the contracts weren't in place, had never been executed. So as a result of that, the QFs, which in this case were wind, weren't able to take advantage of that more favorable standard offer. So that was something that had happened three times.

So what FERC said was, you know, even though a contract isn't executed, even though both parties don't execute it, when the QF comes forward and states that they're ready to negotiate a contract and they're prepared to sell, that's when this legally enforceable obligation attaches. In those Idaho cases that LEO had attached at a time when that standard offer was still available.

So FERC's position was basically that these wind facilities should have been entitled to that particular rate, the rate that was in effect at the time that the LEO was in effect.

Now, those cases -- again, it was a very quirky proceeding, because it came at a time when Idaho was transitioning from standard offer for 10 megawatts to 100 kilowatts. So that's why there were a couple of those cases and that's why FERC, I think, found it necessary to get involved in the case to confirm that the rate that is in effect -- to confirm that the legally enforceable obligation attached at the time the parties were ready to deal.

Ordinarily that really isn't that much of an issue. To be honest, there really isn't -- there really aren't that many other cases out of different jurisdictions where there has been that dispute because, you know, ordinarily you don't have a rate that's got like a time offer on it, you know, where it matters that much. But the LEO is -- the legally enforceable obligation is part of the law.

You know, again, it's a way to sort of prevent contract negotiations from dragging out. If the parties know at the beginning that there's a legally enforceable obligation, they're both essentially going to get the deal done. You're not going to have a situation where -- you're going to have more incentive, I think, for the parties to agree, because that obligation is already something that's in place.

So I don't know if I answered the second part of your question. I'm happy to take a follow-up question.

COMMISSIONER ROKEBERG: Well, thank you very much for your explanation of that particular case. Perhaps I should not use it in that context, but if I could expand it somewhat.

MS. ELEFANT: Sure.

COMMISSIONER ROKEBERG: My inquiry is in areas, for example, in curtailment or -- can you have specific agreements within a contract between an IPP and a utility that would be either -- would be inconsistent with the particular state's regulations, particularly speaking in terms of the context of like curtailment or integration in a congested transmission system, for example?

MS. ELEFANT: Well, I think generally speaking the parties can always negotiate whatever they want. So if they come to an arm's length negotiation, I suppose in a situation if a QF were willing to accept a unilateral curtailment provision within the contract and perhaps it was getting some type of a benefit or perhaps rates were being set in such a way that the QF was able to live with the unilateral curtailment provision, that is something that would be acceptable. The parties can always voluntarily negotiate almost everything they want, even if it is inconsistent with state regulation or with PURPA.

What typically happens in these cases, though, is that the IPP does not necessarily -- does not voluntarily or does not want to voluntarily agree to a unilateral curtailment provision. So in that situation unless -- you know, unless you make clear that there can't be unilateral curtailment, the utility can potentially walk.

There's a case, for example, right now at FERC, and I can't remember if it was either just decided or if the complaint had been filed, but essentially there was a utility, I think it was perhaps in Idaho, that had basically said we want to -- you know, our PPA has a unilateral curtailment provision. If you don't agree to that unilateral curtailment provision, we're not going to sign the contract. So the QF went to FERC and said they can't force us to agree to something, to a unilateral curtailment provision that is inconsistent with PURPA. That would be forcing us to contract away our rights, and that's something that's not lawful; however, if the QFs had agreed and said that this is great; we don't have a problem with this; they certainly could have done that. But what typically happens in these cases, and the reason why it's important to establish the right for, is because what typically happens is that the QF does not want to agree to those provisions.

COMMISSIONER ROKEBERG: And that's where the leverage comes in if there's a LEO more or less?

MS. ELEFANT: Yes. If you know -- if everybody has sort of agreed to what these basic provisions are, if you're going into the deal and you know that you can only have curtailment in a very limited situation or if you know that your rates are going to be based on incremental prices rather than average prices, that kind of sets the starting point. Everybody can agree on the starting point.

The problem, as I understand it, is that QFs have been expending a lot of effort and resources in sort of climbing up to that starting point. I mean, that should be the floor and it's, you know, almost been as if the QF has been in the basement and had to, you know, argue and negotiate to get up to that floor. Everybody should start at that -- you know, the floor should be established, and then beyond that there's more opportunity to negotiate.

When everybody agrees what the floor is, you do have leverage because the utility knows that it can't -- that there are certain areas that it just can't go. So it's -- you know, it can't say we're going to pull this deal away because you won't agree to unilateral curtailment. It's forced to continue to negotiate, you know, when it already -- when it knows that that's something that can't be bargained away.

I think that kind of opens the door for companies to -- companies and utilities to come up with more creative approaches that are a win-win for everybody. You know, when you're not wasting time arguing over something that is already established, you can focus on ways to -- on deals that are win-win for the IPP, for the utility, and for the customers.

COMMISSIONER ROKEBERG: Thank you, Judge. Thank you, ma'am.

ALJ ROYCE: Any other Commissioner questions? Hearing none, thank you, Ms. Elefant, for your presentation.

At this time we'll turn to Mr. Mohler representing Cook Inlet Region.

MR. MOHLER: I have an outline of my --

ALJ ROYCE: Sure. You can distribute them. I can pass them out.

Mr. Mohler, before you begin, do you have an idea of the length of your presentation? I'm just trying to plan the lunch break.

MR. MOHLER: Well, thanks to the very good presentations by AEP and AIPPA, I think it's been shortened some.

ALJ ROYCE: Okay.

MR. MOHLER: So I'd estimate between 20 minutes and a half-hour.

ALJ ROYCE: Okay. Please proceed.

Please identify yourself for the record and who you represent.

MR. MOHLER: My name is Paul B. Mohler. I'm an attorney here representing Cook Inlet Region, Inc. Also, here in the room today from Cook Inlet Region, Inc., or CIRI, are Ethan Schutt, the senior vice president of CIRI and president of Fire Island Wind, and Suzanne Gibson, senior director of energy development for CIRI.

Thank you, Mr. Chairman, Commissioners, and Judge Royce for the opportunity to speak here today. I think you already know the background of Cook Inlet Region, Inc. and the Fire Island Wind project, so I'm not going to spend time on those. Fire Island was not a QF project, so it has some relevance in terms of being an IPP wind power project, but it wasn't negotiated under the QF regulations.

CIRI supports the revised QF regulations -- or largely supports the revised QF regulations that have been proposed by AEP. We do have some differences with those, and I'll talk about those specific areas in a moment. Before I do that, though, in general CIRI's very interested in working with utilities and negotiating with utilities to reach results that work for both CIRI, the utilities, and consumers in the railbelt.

That is, the focus for CIRI is getting projects done, projects that work, and that are investable. That's an important factor in its review and thinking about the proposed rulemaking here; that is, as we go through this, if you have curtailment, for example, that provides for curtailment in situations where there are not system emergencies, is an investor going to look at that and say that project simply isn't going to be investable for us. We won't loan you the money to build that project.

So a touchstone for CIRI in this proceeding has been whether these regulations will provide a framework that's both workable for the development and financing of renewable energy projects.

AEP has done, I think, a very good job of explaining the legal authority to revise the QF regulations. It's unquestionable that this Commission has that authority with regard to the regulations at issue. PURPA provides the overarching statutory authority. The FERC regulations then implement PURPA, and your regulations flow from those.

I referred to the term "cooperative federalism." That's a term that FERC used in its recent settlement with the Idaho PUC. It is simply recognition that there is a relationship between FERC and the state agencies with regard to the regulations that the state agencies are asked to implement. In implementing those regulations, you do have some discretion and a fair amount of authority to recognize the local circumstances in which the regulations have to work.

We support the AEP proposal

relating to avoided costs. In 1982, when this Commission issued its rulemaking adopting the original QF regulations, it recognized that marginal cost was at least theoretically the appropriate way to calculate avoided cost. Marginal cost is incremental cost. Marginal costs and incremental costs are not equal to average costs. Incremental costs should be adopted by this Commission as the basis for avoided cost.

There are also a list of factors that were identified by AEP and proposed in their regulations that departed somewhat from the list of factors that are in the FERC regulations. CIRI would support what I heard as AEP's alternate proposal that if AEP's list of factors was too complicated or wasn't supportable, that this Commission should consider simply adopting the FERC factors. CIRI would support that result. Those FERC factors are at Section 292.304(e) of the FERC regulations. That would be 18 CFR Section 292.304(e).

We would support an incremental

approach for both long- and short-term QF rates. For long-term rates we would support an outcome that included long-term capital costs in the calculation of avoided cost. That, again, is consistent with the FERC regulations.

QFs should have two options for the delivery of power from QF projects; either to deliver the power and be paid at the time of delivery or to provide the power over a specified period of time. That is what Ms. Elefant referred to as the legally enforceable obligation or LEO option. CIRI would propose that a reasonable length of time would be up to 20 to 25 years to comport with what it sees in the market as a typical time period for power purchase agreements or PPAs.

We don't know that that needs to be in the regulations, but if it were in the preamble as an option or a reasonable period to expect contracts to cover, I think that would be an appropriate way to handle that.

With regard to curtailment, again, it should be only for emergency and reliability purposes. The current regulations are consistent with the FERC regulations, but lack clarity. That clarity could come, again, in a preamble comment that makes it clear that the opportunity for curtailment outside of emergency reliability circumstances would be very limited, and that economic curtailment would not be appropriate in any circumstance.

We too recognize the difference or distinction between interconnection costs and integration costs. Interconnection costs are costs of facilities that are used to interconnect the QF project with the utility. As such, they can be identified, they can be costed out with some reliability, and assessed appropriately.

The current regulations do that. Integration costs, however, we would go even further than AEP or AIPPA and propose that all integration costs be rolled into the system costs. As you saw in AEP's presentation, with integration costs ranging from zero to 1.1 to 7 plus or minus cents per kilowatt hour, the costs themselves appear almost on their face to be discriminatory. How can you have zero cents for one system and 7 cents for another project?

Our proposal would be to -- and we put regulatory language into our reply comments that reflects this proposal. Our proposal would be to simply roll all of those costs into the utility's overall costs in the same way that they manage those costs.

If there were a fallback for us, I think that we'd be much closer to AIPPA's position, which would be to provide a presumption that integration costs are zero with a requirement that the utility provide the details for any costs that it thinks are caused by a QF project. But when it does that calculation, it should also include the benefits of cost, because QFs provide both -- they may create costs, but they may also provide benefits when they integrate with a system.

The fourth item you asked for comment on, the RFP, request for proposals; we took no position on. We did, however, in our initial comments propose that in implementing QF rates, it might be appropriate to have some sort of standard form or standard offer contract. In responding to AEP's proposal for an independent monitor, we had some concerns, some reservations about that.

At this point I'm not sure this proceeding is the place to try to craft a standard offer contract. It might be appropriate for a proceeding at some future time. But we don't believe that an independent monitor would be an appropriate -- a mandatory independent monitor would be an appropriate mechanism for negotiating QF contracts.

As I said at the outset, CIRI is very committed to working with utilities to negotiate deals that will work, that can be funded, that are financeable. For us, the potential to get thrown into some sort of mandatory process, I think, just raises concerns and potential unintended consequences that we just can't evaluate at this point. Therefore, we'd ask that that proposal at least be put off and considered as part of a broader implementation at some future time.

Now, you will almost certainly hear that there are a number of aspects of this proposed rulemaking that need to be studied, that need workshops, that need additional analysis. Our view is that that's not correct or that the sequencing needs to be done correctly; that is, you can issue the rules or proposed rules consistent with the recommendations made by AEP, AIPPA, and CIRI. Then with those rules of the road in place, or at least proposed, you would be in a better position to know and the parties would be in a better position to know exactly what kind of workshops might be required, what kind of additional implementation requirements there would be.

So to do studies first and then try to craft regulations, I think, would sequence this just the wrong way and potentially paralyze this proceeding for some indefinite period of time, when if you're going to start attracting capital investment in QF and other IPP projects to Alaska and to the railbelt, you should start as quickly as possible in revising these regulations, put in place regulations that would result in contracts that are financeable and that can attract the investment and lenders needed to build those contracts.

I'd like to conclude by, I think, echoing comments made by Mr. Schutt at the September meeting that introduced and implemented this rulemaking proceeding. That's that IPPs are different than utilities. IPPs are willing to take on much more risk than utilities would in building projects and in going out and introducing new and innovative technologies.

That's not to say that utilities aren't interested in that, but utilities have a different perspective. They are, and rightfully so, very concerned with reliability and ensuring that they can keep the lights on day in and day out. For IPPs reliability is certainly a concern, but they also want to build projects that they can put into the network, that they can get funded, and that will also add to the resilience and reliability of the utility system.

Thank you.

ALJ ROYCE: Thank you, Mr. Mohler. Are there any questions by Commissioners?

COMMISSIONER PATCH: I have none.

ALJ ROYCE: Thank you. Just before I -- thank you, Mr. Mohler. You are excused.

Just maybe take a roll call of people in the hearing room or people on the phone that are supportive. Does anybody else want to make a presentation, other than I see the representatives of GVEA and ML&P. I know they want presentations, but is there anybody else that would like to make a presentation before us today either in the hearing room or on the phone? Okay.

Hearing none, we'll come back at 1:30 and we'll hear presentations by GVEA first and then we'll hear ML&P.

Mr. Thompson.

MR. THOMPSON: If it's okay with Your Honor and the Commission, we had planned on the Alaska Power Association going first to provide the general statement followed by ML&P and Golden Valley.

ALJ ROYCE: That would be fine.

MR. THOMPSON: Okay. Thank you.

ALJ ROYCE: Thank you. All right. See everybody at 1:30. We're off record.

(Off record.)

ALJ ROYCE: We're back on record for the continuation of the public hearing in Docket R-13-002 at approximately 1:33.

Commissioner Pickett is unavailable for this afternoon's hearing. He will review the transcript before taking any action in the proceeding.

At this time, Mr. Thompson, are you ready with your presentation?

MR. THOMPSON: I am, Your Honor.

ALJ ROYCE: Please state your name and identify who you represent and proceed.

MR. THOMPSON: Yes. My name is Dean Thompson with the Law Firm of Kemppel, Huffman & Ellis. I'm here on behalf of the Alaska Power Association.

ALJ ROYCE: Thank you. Please go ahead.

MR. THOMPSON: Okay. A couple of preliminary matters. I am here to summarize the comments that APA has submitted in this docket and to expand on a couple of areas. I don't intend to repeat all of the arguments that were stated in the comments, trusting the Commission has read them, but I do want to clarify that the comments that were submitted in writing and most, if not all, of what I will be testifying to today are the result of a collaborative process of APA's members.

APA represents several electric utilities throughout Alaska, regulated and unregulated, and has a regulatory working group that gets together and confers regarding regulatory dockets such as this and has been doing that for years. APA has participated in many of the Commission's rulemaking dockets, particularly ones relating to PURPA and the more narrow issue of qualifying facilities.

Of course when you have a group

like that, one voice can't speak for all of the members, and that is why in this case, as in other cases, some of APA's members, such as Chugach, Golden Valley, ML&P, have submitted comments on their own and will be testifying before the Commission on their own.

So I guess just preliminarily I believe I am accurately stating the conclusions of the working group that we had, but individual APA members may have a different take on some of the details here. Incidentally, APA wanted to thank the Commission for scheduling a second hearing in this case. APA had requested something like that because, as we speak, many APA members and the general managers and others who might otherwise be at a hearing such as this are in Juneau for a previously scheduled set of meetings.

Just to give the Commission a preview, on the next hearing date, February 4th, currently APA expects that representatives from Chugach, MEA, AEL&P, and possibly one or two others will be speaking at the February 4th hearing.

What I plan to do is to start off by giving you from 30- or 40,000 feet APA's general positions regarding the issues in this docket, and also to share with you what APA believes the disputes in this proceeding should not be about. Then conclude by indicating what we think are the three or four important themes, for lack of a better word, in this docket. I will then briefly attempt to summarize some of the finer points regarding the four issues that the Commission raised in its order and that AEP has submitted comments and proposed regulations regarding.

In terms of overall positions, APA -- they can be distilled down to three. First is that APA believes the requested changes to the regulations are not necessary.

Secondly, APA believes that if the Commission decides it wants to more closely reflect the regulations that FERC has adopted for QFs, that it should do it completely and precisely and not introduce a third set of regulations that are not the

Commission's, that are not FERC's; that they're something different.

And then third, there is one minor amendment that hasn't been discussed other than in APA's initial comments very briefly, but one housekeeping amendment that probably should be done. That has to do with the definition of qualifying facility in the Commission's regulations.

So to add some color to those three points, the requested changes to the regulations are not necessary. I know I personally have a laundry list of regulations that I would like to change, and they can always be improved and tweaked, but it doesn't happen very often. Part of it is because you have to go through a process like this. I think the main reason is because unless it's something significant, unless there's a need for a change in the regulation, there is some advantage beyond inertia to have consistent and predictable regulations through time.

In this docket it has been argued that these regulations were adopted in the early '80s and look how much has changed since then. Most of the Commission's regulations were adopted in the early '80s and earlier. Their vintage does not mean that they're obsolete.

PURPA, the federal statute, has changed in some ways, not ways that affect the Commission's regulations, but PURPA is still the same as it was in 1978 with some minor exceptions. FERC's PURPA regulations are still the same as they were before the Commission adopted its regulations. So the age of these regulations and the enormous strides in technology that have occurred since then do not indicate that these regulations need to be changed.

The main reason that I've heard big picture for why these regulations need to be changed, and I think it was AIPPA -- I'm not sure how they -- but I believe counsel indicated that the current regulations are in violation of PURPA, that the Commission has failed to implement PURPA through its regulations.

The first counter to that

obviously is that the APUC went through a very long process of investigation when it adopted those regulations. Certainly the Commission and the Department of Law reviewed it for legal sufficiency. I would cite you to Order No. 4 in Docket U-81-035. In that Order the Commission addressed comments by commenters at that time saying you can't implement this regulation, because it doesn't conform exactly with FERC's regulations and it will violate PURPA.

The Commission responded and addressed those issues. Starting at page 10 the Commission cited court decisions and FERC briefs in litigation. Suffice it to say, I won't bother reciting for you the Commission's determination, but the Commission determined -- made a reasonable determination that its regulations, as adopted, complied with FERC and adequately implemented its PURPA obligation. Other than in comments, that hasn't been challenged since the regulations went into effect.

So it's one thing to say you don't like the regulations and you think they could be better; you think they could assist IPPs better if they're changed; it's another to say that they're illegal or that you must change them in order to comply with PURPA. Again, PURPA hasn't changed since these regulations were adopted in a way that would affect the validity of these regulations. So that first reason, I think obviously you should take another look at it if you're concerned about that, but a determination has already been made regarding the legality of the regulations.

In the Order that I just cited, the Commission acknowledged that it had flexibility in how to implement PURPA. It acknowledged that it was -- it didn't even have to adopt any regulations. It could have implemented PURPA on a case-by-case basis through adjudication as agencies can establish policy through rulemaking or adjudication.

The Commission considered that option and rejected it. It said, no, we want to have regulations. But the Commission said it doesn't have to be a verbatim copy of the

FERC regulations, and we're going to tailor it to the issues that we think are most important and the circumstances under which these regulations will be implemented. So the Commission did that, and the current regulations reflect the items that the APUC determined were most important in its implementation.

Substantively, there are only two areas that, broadly speaking, are covered in the FERC regulations that are not in your regulations. Just as I mentioned before, but the first is the express recitation of the QF having the option to sell QF power as available or pursuant to a legally enforceable obligation. Related to that, if the QF chooses LEO, that it can choose to have pricing determined at the time of delivery or at the time of the legally enforceable obligation.

The second issue is that -- or the second area where the FERC's regulations contain something that your regulations don't has to do with the factors to consider when determining avoided cost. FERC in its rules at Section 304(a) lists four broad areas of factors that should be considered. Your regulations contain three of them. In some of those your regulations don't go to the same level of detail, but that is one area, that list of nonexclusive factors, you could beef up yours if you wanted to add the one area that isn't addressed in your regulations. But by and large, even with the factors, your regulations hit the ones from FERC's regulations that the APUC thought would be most germane to issues in Alaska.

Incidentally, I'm not aware of any practitioner who has believed, in Alaska, that the factors under the FERC regulations or the QF option to sell pursuant to an LEO, that those rules did not apply in Alaska simply because the RCA's regulations don't include them. I know I have advised my clients that when you're looking to what your obligations are vis-a-vis a QF, you should look at the Commission's regulations, but if you need to determine what they mean or the scope of what factors should be taken into account, you should look at the FERC's regulations and you should look at FERC precedent.

The APUC, interestingly enough -- and I apologize, I don't have the docket number for you, but i will find it and provide it to you -- but shortly after the APUC adopted the current regulations, the APUC adjudicated a QF complaint case against Golden Valley Electric. Throughout it there are citations to FERC regulations, including the legally enforceable obligation option and FERC precedent on the finer points. You will -- there are probably other cases that were litigated where that occurred, but --

ALJ ROYCE: And that docket was not cited in your comments?

MR. THOMPSON: I don't believe it was, Your Honor.

ALJ ROYCE: Okay. Thank you.

MR. THOMPSON: But it --

ALJ ROYCE: If you can provide the cite.

MR. THOMPSON: Golden Valley and Healy Power, Inc., HPI, but I will find it. I tried to find it at lunch. I just misplaced it.

ALJ ROYCE: Okay. Thank you.

MR. THOMPSON: So the Commission's current regulations, I don't think anyone has construed them as rendering the FERC's regulations or FERC precedent as being irrelevant. Certainly it's instructive and constructive authority and probably helpful at the margins in interpreting PURPA obligations. It may not be binding authority the way your own regulations are, but they have been available.

The one minor but necessary amendment that I referenced before is in the definition of qualifying facility, which is located at 3 AAC 50.820, Subsection 11. It states that qualifying facility means a cogeneration facility or a small power production facility which meets the criteria prescribed by Part 292, Subpart B of FERC's regulations as effective June 30th, 1982, including size, fuel use, ownership, and efficiency standards.

That was correct when these regulations were adopted. FERC has amended its regulations in that section since then, not in a way that materially affects the issues that we're discussing in today's hearing, but it has modified those regulations, particularly in the wake of the Energy Policy Act of 2005. Those changes affect who is a QF and who isn't.

So to the extent that this definition references FERC regulations, it would seem prudent to have it reference the current regulation. I know the Department of Law has had various issues with incorporating statutes by reference. I don't know where -- what the latest thinking is on that, but I raise this as an issue because this is -- although it's a technical and administrative one, at some point it may have some relevance.

Okay. I wanted to move on to what APA believes the disputes in this proceeding should not be about. I'll follow up by telling you what we think it is about. The reason I go through these is because we have heard various arguments for the need to revise regulations, and AEP has focused on the regulations to a large extent, but other commenters have raised a lot of issues that APA doesn't believe are really relevant to the issue of whether these particular regulations should be modified. These regulations, of course, address utility obligations to a qualifying facility. These regulations don't purport to address all things related to IPPs or renewable energy or anything of that sort.

So the disputes in this proceeding should not be about, No. 1, whether renewable energy is good. In APA's initial comments we tried to highlight that APA and its members have for decades been in favor of increasing use of renewable energy production, reducing fossil fuel production if and to the extent it can be done without harming ratepayer interests. Certainly in the examples in APA's comments and in other comments filed by other utilities, utilities have been at the forefront in Alaska of developing hydroelectric power. Utilities own hydroelectric power, own wind power, purchase renewable energy from qualifying facilities and others. So this should not be a referendum on whether increasing use of renewable energy is good or not.

As ML&P indicated in its comments, from an avoided cost perspective, renewable energy isn't an end in and of itself, but to the extent that it can reduce customer rates certainly, increase reliability, increase diversity, that's a good thing. So there isn't a dispute about that. But that doesn't mean that the regulations need to be revised.

Secondly, the disputes in this proceeding should not be about House Bill 306 or Alaska Statute 44.99.115. It's tempting -- I know it's tempting to cite that whenever it appears to support your argument. APA attempted to provide its interpretation of that legislation in its reply comments on pages 4 through 6, so I won't repeat the arguments, but the bill and the statute and the legislative intent say what they say and they mean what they mean.

But it is improper to say that the statutory energy policy that was adopted in that statute has a goal of a certain penetration by 2025. There was a statement of legislative intent; that is not the same as being adopted in statute. What legislators or others have said about it afterwards, certainly that may reflect what their intent was, but in statutory construction that doesn't -- isn't determinative about what the scope of the statute is.

The statute is not in AS 42.05 or 42.05 or 42.06, the statutes that govern the operation of the RCA. So it may not be popular to appear to minimize the scope of legislation that adopted the state energy policy, but it needs to be given the effect that a plain reading of the statute provides.

Third, the disputes in this proceeding should not be about the necessity to increase the percentage of energy production by IPPs. This argument is raised in various contexts, but the idea is that penetration by IPP production is an end in and of itself. The percentage of IPP production in Alaska is lower than what it is in the competitive markets of the Lower 48, and apparently that's a bad result. Whether it's a bad result can be debated, but it certainly doesn't have direct relevance for your regulations governing qualifying facilities.

Another argument that has been raised in this docket regarding this is that we have to go beyond encouraging qualifying facilities without harming ratepayers, which is the purpose of your regulations and we have to encourage IPPs, not only in and of itself, but because it's necessary for Alaska to attract the private, quote, unquote, capital that's required to build the renewable energy projects that the state needs.

I've never heard that argument developed, but suffice it to say that electric utilities in Alaska, whether they're private or government-owned or cooperative or investor-owned, there isn't a shortage -- an unusual shortage of capital, debt capital or equity capital available to construct the projects that need to be constructed. So utilities aren't against IPPs. Utilities in Alaska purchase power from IPPs or QFs, but to say that something special has to be done in RCA regulations to deal with a credit problem, APA isn't aware of any such credit or capital issue.

Last, the disputes in this case should not be about whether IPPs are necessary to lower customer rates. That's another argument that usually gets thrown in at the end. Rates in Alaska are high; we need to do something about it; let's change the regulations. These regulations, again, are dealing with obligations to a qualifying facility, which is more than anything about avoided cost.

The whole avoided cost concept is designed to leave ratepayers economically indifferent to where the utility purchases its power. It was never designed and isn't being implemented to reduce customer rates. That's the point. The point of PURPA is that if you are in this special class, qualifying facility, utilities are required to provide to the QF all of the benefits of trade. So the idea is not to help the customers in terms of rates. It's to not help them, but not hurt them, which as you can imagine, is a fine line to be on.

I think it was AIPPA's attorney indicated earlier that with the proposed regulations, QFs or IPPs are not looking for preferential treatment. Well, PURPA and these regulations by design create preferential treatment. It's not a bad thing, but we should call it what it is.

If ML&P wants to sell power to Chugach, it has to go and show Chugach that its customers will be made better off as a result of that. They negotiate on how to share the gains from trade. What ML&P can't do is go and say, you have to buy from me and you have to pay every cent that you would have otherwise spent to produce that power yourself, thus leaving your customers economically indifferent.

That's a special right that's provided to qualifying facilities under federal law, and the utilities and APA recognize that, but it isn't about saving money for ratepayers.

So that's APA's position, respectfully submitted, on what the issues in this case should not be about, should not turn on. The important big-picture issues from APA's perspective are threefold in this case.

The first question is: Has AEP proven by a preponderance of the evidence that its proposed amendments are necessary? If not, the regs should stay the same. As I indicated before, while we may want to tweak regulations from time to time, unless there's a compelling reason to do so, there is some value in consistency and predictability and in avoiding the potential for unintended consequences from hastily amended regulations.

Big picture item No. 2 is, in this case I found myself wondering, and I think it's a good question to ask: Are some or most of AEP's issues or complaints really about what the rules should be, or are they about AEP's complaints about how it believes one utility has improperly followed those rules? It's a distinction that matters. I can't help but think that part of what is being argued about here is an adjudicatory matter, the details. The avoided cost calculations, as I'll talk about briefly and others will talk about in greater detail, are complex technical matters. It can be done, but it isn't something that can be exhaustively addressed through regulations or even effectively addressed through regulations, other than providing some general principles. But it is an issue that seems to exist in this case, whether this case is really an adjudicatory complaint more so than an actual rulemaking about regulations that need to be changed and broadly applied to all regulated utilities in Alaska.

One example on that that I want to make sure is clear is this case more than other rulemaking cases seems to be -- seems to have wind power, nonfirm wind power in the background. For years all of the significant disputes about PURPA were from cogeneration. This is more about wind power. When you're talking about integration costs and levelized pricing over a forecast period, that's a wind type of issue. I'm not trying to dismiss that as an issue, but it doesn't have the feel of something of broad applicability that would justify amending the regulations.

The third and, from APA's perspective, most important big-picture issue is ensuring that whatever is done or isn't done in this case, that customer rate interests are protected. APA believes that's especially important when you're dealing with trying to change the rules or the application of rules with regard to avoided cost and qualifying facilities. Again, the whole paradigm is designed to leave the customers only economically indifferent, to not help them, but not hurt them.

So if you are considering changing the rules and if those changes may have impacts on how avoided cost is calculated and implemented in contracts, the customers' interests are directly implicated by that. I'm overstating -- oversimplifying this, but to a large extent the utilities are going to recover their costs, whether they pay avoided cost or two times avoided costs. In general, the utilities are going to recover those costs through its cost of power adjustment. If it pays two times avoided costs, the customers will just pay significantly higher rates.

So APA and its members are interested in these issues and are cautious about changing these regulations primarily -- well, I would say solely because the concern is that somehow implicitly or explicitly it will result in the utility having to pay greater than avoided cost. We'll argue about what avoided cost means, but whatever it means, we think it's important to make sure that customers are not saddled with the rate increases that result if we get it wrong.

The ways the customers can be negatively impacted are twofold. No. 1, the most obvious is directly in rates, as I just described with COPA. The second way is indirectly through increased base cost rates from increased administrative costs on the part of the utility. The utilities recognize that to implement PURPA, it's going to have to incur administrative costs that it didn't otherwise in negotiating deals with QFs and determining avoided costs and the regulatory aspects of it, but it is something to keep in mind when someone is proposing that every regulated utility in Alaska file detailed, incremental avoided cost calculations annually with the Commission regardless of whether there is any dispute with a QF or if they've ever had any expression of interest from a QF.

Those are real costs that eventually one way or the other, through labor and other costs, get reflected in customer rates. So APA's overall interest is that customer rate impacts be carefully considered throughout the entire process of considering avoided cost or qualifying facility related amendments to regulations.

Moving on to the four issues that the Commission sought comment on and that AEP proposed regulations on. The first one is avoided cost, and that can be divided up and should be divided up between the avoided cost definition and the avoided cost methodology. In the comments those two concepts get blurred, but I think if we're talking about changing regulations, that distinction should be made.

So apart from the methodology, let's first talk about the definition. The Commission's definition of avoided cost is identical to the FERC's definition of avoided cost except that the Commission refers to costs and FERC refers to incremental costs. But as we argue in APA's comments, the term "incremental" in the definition is redundant, because both definitions prescribe a but for analysis in determining the avoided costs.

For example, your regulations define avoided cost: The cost to an electric utility of electric energy or capacity or both, which but for the purchase from the qualifying facility, the utility would generate or purchase from another source. The economists who deal with this on a daily basis or even less frequently will tell you that the only way to satisfy that definition and determine a true avoided cost is to calculate total costs without power from a QF and total costs with power from a QF and subtract the two. That gives you the avoided cost. That, by definition, is an incremental cost analysis. It's calculating the delta. It's calculating the difference between those two scenarios over some period of time. That's where the implementation disputes start.

ALJ ROYCE: Excuse me.

Mr. Thompson, how do you respond to Ms. Clemmer's argument that the language in the FERC preamble that system average avoided costs are not the same as incremental avoided costs?

MR. THOMPSON: I would agree that, from a definitional standpoint, system average cost is different from incremental cost.

ALJ ROYCE: Okay.

MR. THOMPSON: And when I get to the methodology section, I'll address the apparent conflict in the regulations that exist.

ALJ ROYCE: Okay. Thank you.

MR. THOMPSON: So the definition itself implies an incremental analysis. The definition itself, when you do a but for analysis with and without, doesn't ask you to average costs over anything. At its most simple basis if you're asking what is the avoided cost of 1 kilowatt hour, calculate all the costs for generating 500 kilowatt hours. Then calculate your costs for generating 501 kilowatt hours, and do a subtraction of the total, and you will get an incremental cost for that kilowatt hour. So from a definitional perspective you don't need incremental.

As APA has stated, if you have your heart set on it and you want absolute consistency with the FERC's definition, APA doesn't believe it will have any effect by changing the definition to include incremental. So that's our position regarding the definition.

The more controversial issue is the avoided cost -- the methodology that's to be used. The one last item that came up in reply comments, or actually maybe it was in initial comments by AEP, but while APA thinks the definition is fine the way it is, if you have your heart set on including incremental, APA doesn't believe it will cause any difference from a definitional standpoint. But APA does oppose AEP's proposal to add a clause to the definition that doesn't exist in the Commission's regulations or FERC's regulations.

That clause that AEP proposes to add at the end is with the presumption that the most costly increments are displaced by a QF before less costly increments. APA opposes including that in the definition. If we want -- if there's merit to that at all, it has to do with the methodology, not the definition.

But, No. 1, adding a presumption, a substantive presumption to a definition is generally disfavored. But No. 2, the presumption is either -- as we explain in our brief, it's either redundant or completely unnecessary or worse, it is an attempt to inject systematic error into the avoided cost calculation itself. APA explains that in its pleading; I won't go into it. But either way APA believes that that isn't necessary and actually would do harm to add that clause to the definition.

Moving on to the avoided cost methodology. Again, this is one that bears clarification, because all we're talking about is for nonfirm energy. That's the scope and extent of the dispute here. The methodology -- the general methodology that applies to both firm and nonfirm broadly is found in Section 770(c) of your current regulations: Rates for purchases of electric power must be just and reasonable and must not discriminate against qualifying facilities or adversely affect the consumers of the electric utility. That's the broad rule.

Then for firm power, Subsection 770(e) states that: Purchases -- for purchases from a QF that supplies firm power, rates must be based on the cost of energy and capacity which the electric utility avoids by virtue of its interconnection with the qualifying facility. So, again, without invoking the term "incremental" or without even invoking the term "avoided cost," the Commission has set forth an incremental analysis there. It's the cost that you avoid by virtue of purchasing from a QF. That's the general rule that applies to firm power.

Now, if we go back to Subsection (d) of 770, the general rule for nonfirm power is similar. Rates must be based on the cost of energy which the electric utility avoids by virtue of its interconnection with the qualifying facility. So far they're identical. It prescribes an avoided cost methodology, and it's necessarily incremental.

The problem is Subsection (d) goes on to say: Rates under this subsection, referring to the nonfirm power, must comply with the following requirements. Subsection 1 provides a formula. That formula, I think, can be fairly described as an average production cost over a 12-month period.

How APA interprets this is slightly different from the others in this docket. Having reviewed the APUC order in order -- or Docket U-81-35, I don't think the APUC was saying that this average production cost is the definition of avoided cost. They clearly weren't saying that this is equal to incremental cost. I think the -- these are my words, not the APUC's, but I don't see anything that contradicts this. I think the Commission was coming up with a methodology to do a proxy calculation, to calculate an estimate of what incremental costs would be if you went through all of the details and resolved all of the methodological issues and timing issues of incremental costs.

I think that's a distinction. It's not just a technical distinction. The Commission wasn't saying this is how avoided costs should theoretically be calculated, and they weren't saying this equals incremental costs. They were saying for convenience and administrative efficiency, for nonfirm power only, we're going to prescribe this method to calculate a number that we think will be close to what the true incremental costs would be. Sometimes it may be higher;

sometimes it may be lower.

I think further that since the Commission did not adopt that formula for firm energy, I think it can be fairly inferred that the Commission thought that for nonfirm energy it wouldn't be -- precision wouldn't be as important as for a 100 megawatt firm cogeneration facility. I think -- now I'm really speculating here, but.

I think the Commission was at that time thinking that we need this formula so that utilities can start offering their standard offer for 100 KW or less in their tariff, which FERC's regulations -- that was the main thing that the APUC had to do to implement FERC's regulations. It had to do it quickly. It had to require the utilities that it regulates that they put in their tariff a standard offer rate for small, tiny, nonfirm QFs, 100 KW or less.

By the way, through a later section that refers to Section (d)(1), that's what this does, and that's where we -- the vast majority of times that you have come to apply or see this formula, it's when utilities submit their quarterly COPA filing and update their nonfirm purchase power rate for 100 KW or less, and they use this formula. It's a proxy for incremental cost.

The complaints that are raised here were raised back in U-81-35 that, oh, that's average cost; that's not incremental. The Commission said we know, but this is an administratively practical way to do this. As being someone who has done these calculations for very tiny utilities and updated it and had QFs appreciate being able to see a ballpark estimate of what we're talking about for the utility, I think it's worked very well for that purpose.

What wasn't contemplated, certainly not expressly, is a 25 megawatt nonfirm wind farm. So I understand the reason that there's a dispute about this now. So I think we can -- to analyze this issue I think we should distinguish between the standard offer rate for very small and maybe even larger than 100 KW. You can get a lot larger than 100 KW, and you're still talking about a QF that's so small that the difference on a quarterly basis between incremental costs and average production costs won't be significant and may benefit the QF.

So if we separate those out, first dealing with the standard offer issue, APA believes that this formula should continue to be used for the standard offer rate. The electric utilities have to have all of these costs as part of their COPA filing. It makes it easy. It adjusts with the cost of fuel, which is usually the incremental cost at issue for small utilities, and it serves a purpose of providing notice to potential QFs that may be larger or smaller of what the going rates are.

I believe that AEP has said -- and, again, I'm not talking about the large ones yet -- that even for these small standard offers, you have to use incremental cost, and don't tell me you can't do it. It can be done. Sure it can be done. AEP said, but if you're concerned about the impacts on these small standard offer rates, maybe just calculate it once a year. So calculate incremental cost once a year.

This will be addressed by others, but how do you do that? For one year? Again, the timing of a true incremental cost, if we want to truly calculate incremental cost, we'll do it by kilowatt hour, or we'll do it by minute, or we'll do it by second, or we'll do it by hour, or by day, or by month, or by quarter. Whatever you want to choose, you can calculate an incremental cost, but when you get out to a year, to say, oh, just do it annually and that won't be a problem doesn't resolve the methodological issue of how you calculate an incremental cost versus an average production cost.

Can you do it? Certainly. Many people in this room can do it. They may have slightly different methodologies for getting there, but when you're talking about a small utility that has never seen a QF, but has to under your regulations provide an updated, nonfirm purchase power rate standard offer every quarter, to require them to do incremental cost system modeling is something that's unreasonable when compared to the benefits from that calculation.

Our position is the APUC correctly made this call, certainly for those QFs, that this is not a perfect incremental cost calculation, but it's a proxy from readily available data that gets you pretty close.

With regard to large, nonfirm QFs, the regulations do provide an out from this formula, and that is that it says unless otherwise modified by the Commission. I would think that if you have a very large, a 25 megawatt QF, it would not take much of a -- it wouldn't take much to persuade the Commission or a utility that this is a size where it's worth modeling what the incremental cost would be.

I don't think it's that controversial, and I may be wrong and other utilities can speak up, but for large, nonfirm QFs, I think a utility would want to have the avoided cost calculation based on incremental cost, in part, especially if you're talking about a 25-year contract and projecting what the rates -- what the avoided cost rates will be over a 25-year period, projecting fuel costs over a 25-year period, and doing the modeling with and without on a daily or a yearly basis, the utility wants to get it right. If the utility calculates incremental cost, apart from errors in estimating future gas prices or fuel prices, the utility wants to get it as right as it can with the data that it has.

It wants to get the modeling right, because if it's wrong and the utility is locked into paying costs that are 50 percent greater than what its actual avoided costs end up being, the ratepayers pay higher rates. If you're doing estimates, you're going to be wrong; you know that, but you need to get it as right as you can. So that's what electric utilities would want to do if you're talking about a long-term contract with a large, nonfirm provider.

So APA believes you don't have to throw the baby out with the bathwater and just delete this average production cost formula. It's a proxy for incremental costs that works for the small utilities -- or small QFs and small utilities, but if you're talking about a large -- very large nonfirm QF, the Commission can certainly order that it be incremental cost if there's even a dispute about it.

On this point, AEP's objection to that is, well, we shouldn't have to come and ask you to resolve a dispute we're having with a utility about this. I believe it was AEP who said that the Commission decided against case-by-case implementation of PURPA. Apples and oranges. The case-by-case implementation, as I discussed earlier, is whether the Commission was going to adopt the regulations at all or instead implement PURPA through adjudication. The Commission chose to do it through regulation. That didn't mean that there would never be a dispute between a QF and a utility that the Commission would have to arbitrate.

So the case-by-case analysis choice has not precluded the Commission from having what makes sense to me, a fallback clause that if this proxy doesn't work for a particular situation and the parties can't work it out, come tell us and we'll decide. I can't imagine that the Commission would look at a very large QF where millions of dollars are going to be paid by ratepayers and would say, no, you have to use this average production cost and ignore what the actual incremental cost estimate is over time. So this may be one of the areas where you're being asked to, through a rulemaking, adjudicate a dispute between one QF and one utility.

Lastly, as a complete alternative, if you -- APA doesn't believe you need to change the regulations at all as we said, but if you do want to clarify that a large QF would have the ability to insist on something other than the average production cost proxy, one simple change you could make is to Subsection (d), the last sentence, where it says: Rates under this subsection must comply with the following requirements. You could instead say: Rates for the standard offer for QFs selling 100 KW or less must comply with the following requirements. That would exclude entities that weren't under the standard offer and would kick them back up to the body of Subsection (d) that says that the rates must be based on the cost of energy which the electric utility avoids by virtue of its interconnection, which is the same as what's available to firm power. So if you really think there's a compelling reason to make this distinction, that would be one way to do it that would do less harm than what AEP has proposed.

The next issue that doesn't fall cleanly within the four issues that the Commission raised in its order, but has been raised here, is the issue of the QF option to sell power as available or pursuant to a legally enforceable obligation. APA -- regretfully, we did not address that issue in our comments. But as I indicated before -- well, I guess we did refer to it in our reply comments, Exhibit 1, APA Exhibit 1. That is where APA took AEP's proposed amendments and did a red-line comparison with the FERC regulations that AEP was seeking to model.

At page 6 of APA Exhibit 1 we show a comparison between what AEP is proposing and what the FERC regulations require regarding the QF option. As we indicated in the italicized text, AEP's proposed new Subsection 77 (e) is identical to the text in the FERC's regulation other than some numbering conventions. But that -- like I said before, I think the utilities that I've worked with, they have recognized that if a QF wants to sell pursuant to a long-term agreement, that the utility can't say, nope, the only way we'll purchase power from you is if you -- is if it's just on a short term, as-available basis.

So this doesn't seem to be, again, an issue in dispute, other than possibly if AEP believes that it has been treated that way by another utility. But the FERC regulation is clear on this. The APUC didn't see the need to adopt this in its regulations, but I think you'll see in other cases where the Commission has addressed it, the notion that a QF has that option has not been in question.

So do we need to include this language in the RCA's regulations? It really depends on if you want to go towards verbatim implementation of the FERC's regulations, then you should adopt them verbatim. Is it necessary? I don't think so. If an issue regarding this option comes up, I'm sure that the Commission will look to the FERC's regulations for guidance on this.

This concept really is fundamental to the PURPA avoided cost concept. It also definitely relates to the curtailment issue that the Commission's regulations does address expressly in Section 770(b)(1) and then also in 770(h). 770(h) clearly contemplates a sale of QF power pursuant to a long-term contract.

That Subsection H says that an electric utility or QF may agree by special contract to different rates, terms, or conditions for purchases otherwise required by the section. A contract between an electric utility and a QF is valid if the Commission determines that the rates, terms, or conditions or purchases are just and reasonable to the customers of the utility and in the public interest. Here's the important language: The contract may not be nullified under 3 AAC 50.770(b)(1), the curtailment section, without prior Commission approval. So the Commission didn't implement all of this in precisely the way that FERC's regulations did, but I think it can be fairly inferred that a QF does have that option.

Regarding avoided cost factors, and I indicated earlier that the avoided cost factors that the Commission has in its regulations are -- three out of the four are very similar, if not identical, to the FERC's regulations. The FERC's list of factors are not exclusive, but it basically gives guidance on when you're calculating avoided cost, when you're calculating the cost -- modeling the cost without the QF purchase and with the QF purchase, you take into account all factors of cost and benefits.

So, again, the Commission has three out of four, in general, and those seem to be the ones that the Commission thought were most important in the types of

QF scenarios that it would run into. Those factors are listed at Subsection 770(e)(1), (d) through (f), the availability of capacity or energy from a QF during system and daily peak periods. The ability of the electric utility to avoid costs due to the availability of energy or capacity from the QF, and the cost or savings resulting from variations in line losses due solely to the purchase from QFs. Those are all logical factors that are referenced in the FERC's regulations and provide sufficient guidance.

One issue that was addressed obliquely in the different comments is that AEP proposes to eliminate the definition of firm and nonfirm from your regulations and to eliminate any reference to firm or nonfirm in your regulations. APA obviously opposes that. The firm and nonfirm definitions in this regulation are consistent with what we all in the industry understand the distinction between firm and nonfirm to be in most cases.

That definition has been helpful in other contexts besides these regulations, because it's a definition that comes up in power sales agreements between utilities and in rate schedules. So it's a useful distinction to make, and it's an important distinction under the Commission's regulations. The main way that I think of it as important is when a qualifying facility says, hey, I want to sell you power; how much would your avoided cost be? My first question is: Is it firm or nonfirm? Because if it's firm power that the QF is going to sell and it will allow the utility to defer or avoid the cost of constructing a generation plant, then that has to be accounted for in the avoided cost calculation, in addition to the avoided costs associated with the energy.

So it's a completely different -- or it's a broader analysis if you're talking about purchasing firm energy. The Commission's reporting requirements in its regulation requires the utility to provide its plan for the addition of capacity and for purchases of firm energy and capacity, because you're talking about what the utility can avoid, costs that it can avoid in the future. That is all relevant if you have a QF that's providing firm power.

If it's a QF that's providing nonfirm power that you can't count on and you can't plan your system regarding that, then they're entitled to avoided energy costs, but not avoided capacity costs. So it's an important distinction, and deleting any reference to firm or nonfirm creates more areas for dispute than it solves.

Next, AEP requests a regulation that would require all regulated electric utilities to file all of its avoided cost data, avoided cost estimates, all the supporting data with the Commission once a year. Already under Subsection 790(d) utilities are required to make their estimated avoided cost data available for public inspection. That allows a qualifying facility, a potential qualifying facility to get some idea about those costs.

When a utility makes that information available, it doesn't have a particular QF in mind. It's an estimate based on certain assumptions. Before the utility could enter into a long-term contract with a large QF, it would have to model that particular QF. So this data, these are not avoided cost rates that the utilities make available. They're estimated avoided costs and capacity plans for five years and ten years.

So utilities already have that obligation, and unless and until there's a dispute with a QF over the information that they're being provided, there's absolutely no need for you to be barraged with annual filings of all of this data from every regulated utility in Alaska. For the vast majority of regulated utilities, they don't have any QFs that are seeking to provide service to them. Those that do, they don't have any disputes with them about their avoided cost data. So this is an overbroad filing requirement that will unnecessarily add significant cost and burden to utilities, their customers, and this Commission.

Incidentally, regarding that requirement, APA's reply comments at Exhibit

I shows a comparison between what FERC's requirements are and what AEP has proposed. That can be seen starting at page 7 of APA Exhibit I.

ALJ ROYCE: I'm sorry, is it Exhibit 1 or I? I'm sorry.

MR. THOMPSON: I'm sorry, it's Exhibit 1. You're right.

ALJ ROYCE: Thank you.

MR. THOMPSON: On that page, that shows a significant deviation and modification from the FERC regulation. So if you're going to adopt the FERC regulation regarding data filings or data availability, you should adopt the FERC regulation. The parts that are excluded are things like the applicability provision. FERC's regulations apply differently to small utilities than large utilities and in significant ways.

FERC's regulations also provide a special rule for small electric utilities. AEP simply deletes it. FERC's regulations provide, at page 8 of Exhibit 1, a special provision for substitution of an alternative method for the cost information that's to be provided. So apart from the unreasonableness of requiring an annual filing with the Commission, if what is actually filed and the type of data that needs to be collected, if we're going to go with FERC's method, we should go with FERC's method.

APA believes that the RCA's current data availability requirements are sufficient and is not aware of any significant disputes regarding that, other than some isolated cases between AEP and one utility and maybe another QF and another utility. But that seems to be an implementation or interpretation issue rather than an inadequacy of the Commission's current regulations.

Moving on to integration charge regulations. APA didn't have a lot in substance to say about this, and I won't add that much to it. But there have been some developments on this, and other APA members will probably speak more directly to this. But the regulations that AEP proposed at, I guess it would be 770(d), APA doesn't have any general objection to the extent that they propose general rules that would require just and reasonable treatment and nondiscrimination and avoiding double counting. All of that seems nonobjectionable as far as it goes with a couple of caveats.

Provided that adoption of this regulation would not preclude a utility from addressing integration costs through the avoided cost calculation instead of through assessment of integration fees. That's an important distinction, because there are utilities in Alaska, and I would say most of them would be my guess, would not calculate an integration fee, a separate fee. Instead that would be part of the comparative analysis. What are our costs without the purchase from a QF? What are our costs with a purchase from a QF?

When you model that, you do the system dispatch modeling, the case with the purchases from the QF may include some additional gas costs. It may -- a unit may be running more often. You may have a different spinning reserve obligation. All of that gets factored into the comparative dispatch analysis, and when you subtract the two numbers, integration costs are necessarily reflected in that avoided cost calculation.

So these regulations should not preclude a utility from being able to address integration costs in that manner. But if we don't have a dispute about that, APA does not have any principal objection to the general content of this regulation.

The one exception substantively is Subsection (d)(5). In that section the rule says: Integration fees shall not be justified if they are the result in whole or in part of outdated, inefficient, or ineffective management or operational practices by the electric utility that could be remedied at a reasonable cost to the utility.

That is the type -- that's a good example. That's an adjudication issue. That's not something that you can effectively implement through a regulation. It addresses issues of prudence. These are costs that the utility is going to be incurring and recovering to some extent through base rates. It's not something that you can just say, oh, integration fee; you have to come and prove that that operation or management practice was prudent in order for it to be includable as an integration cost.

The idea behind it is fine. I think we could agree that costs that are proven to be imprudent shouldn't be recovered in electric utility rates, and they shouldn't be recovered in avoided cost calculations. But to have it as a requirement of the laundry list of costs that get included seems to be problematic.

In addition, beyond the actual proposed regulation, there was a proposal from, I believe it was AIPPA and possibly CIRI -- I don't recall if it was both of them -- that there be a presumption that integration costs are zero. I guess the idea would be that until you come and prove the justification for your integration fee under this regulation, that you just assume that it's zero. But if a utility accounts for integration costs through its avoided cost analysis, how do you implement that presumption?

One way to do it is calculate your costs without the QF purchase, calculate your costs with the QF purchase, but exclude -- go and figure out all of the costs in your dispatch model that necessarily increase with that change in load and exclude those costs unless you can prove that they're reasonable?

That presumption is unreasonable. Certainly, the utility in the case or in negotiations should have to justify its assumptions that it's using in its dispatch model. That's what the argument -- if there is an argument, that's what it's going to come down to, is in these dispatch models, what did you assume -- how do you treat hydro? How do you treat these different units? What are the inputs? Obviously those have to be justified, and they have to be agreed on or adjudicated by you in a contested case. But to simply have a presumption that they're zero is a systematic error that goes against the customers really.

If you make that presumption that it's zero and you're wrong, that it's positive, which likely it's going to be, it's the customer that ends up paying a price that's higher than avoided cost. This is an example of something that, if this got enacted, customers as a result of these regulations could end up paying higher than avoided cost implicitly because of something like this. So APA opposes any type of presumption that these costs are zero.

Finally, AEP cited an NREL study that purportedly conclusively indicates that fuel cost savings always outweigh cycling costs when utilities are doing these calculations. I won't spend much time on it, but they didn't conclusively resolve that for Alaskan utilities or any particular Alaskan utility. The idea is that you have to do the modeling to determine what those costs are. You can't make any general statements that integration costs are always zero or always minimal or that utilities always exaggerate them.

If you are really interested in

avoided costs and incremental costs, you have to do the modeling and you have to get the modeling inputs right, and you have to resolve any disputes about the modeling inputs. That will determine whether those costs are positive or negative or what their amount is.

Moving on to curtailment. The Commission's regulation regarding this is at 770(b)(1), and it's almost -- almost identical to the FERC's regulation, even more concisely worded. But I think everyone agrees that substantively the operational circumstances exception in your regulations is similar to FERC's.

In addition, what APA has cited, but I don't see anyone addressing it, is that the related section is 770(h). I read that to you before, the last sentence of it is what's relevant: That a contract between a QF and a utility may not be nullified under 770(b)(1) without prior Commission approval.

So internally just your own regulations contemplate that if a utility and a QF enter into a long-term agreement where the price is estimated at the time of the agreement and estimated for the future, that the operational circumstances exception, (b)(1), can't nullify that pricing agreement that was made between the utility and the QF. It isn't as explicit as the FERC orders have been implementing their own regulation, but we do have this section.

As APA has argued, APA doesn't have an issue with the general proposition that the FERC's rule as explained by FERC and as interpreted by extensive firm precedent does not allow the utility to curtail for economic reasons except under limited circumstances when the QF provides power on an as-available basis, not pursuant to a contract, and when the price is determined at the time of delivery for that as-available basis sale.

So this doesn't seem to be much of an issue except between AEP, and according to AEP, Golden Valley. So the dire need for clarity on this and to draft preamble language that tries to summarize the latest FERC precedent on this seems unnecessary.

It's another way that this case feels more like an adjudication of a dispute or a potential dispute rather than the need to change these regulations after they've been in place for 30 years. This issue of your operational circumstances exception has not come up, that I'm aware of, in any other cases other than what AEP has referenced.

So the current language was based on the language of the FERC regulation. It is still entirely consistent with that definition. There's extensive FERC precedent that provides guidance on what FERC meant, which also carries over to what your regulation meant since yours was based on FERC.

In addition to that, we have the record in this docket. Regardless of what you do with these regulations, I think a utility would be hard pressed to come in and argue that that operational circumstances exception applies broadly to all circumstances in light of all of this contrary authority.

So it doesn't seem like this

scenario needs to be amended. If you really want to amend it to try to capture the scope of the FERC precedent that's interpreted the regulation, we can do that and APA would be happy to participate in coming up with the language. The currently proposed language APA doesn't think has gotten it right. It's a good attempt, but we would want to be more -- we would want to look at that more closely if that's the way that the Commission wants to go. But we believe that it's not necessary.

By the way, I've got two more issues. I will be wrapping it up pretty quickly here.

That is an issue that if you want FERC precedent captured in additional language, that's the type of issue that would be good for the workshop, which I'll talk about -- technical workshop, which I'll talk about later.

Our next issue is the independent monitor and mediation requirement. APA, for the reasons that are explained in its reply comments, opposes this amendment for three general reasons.

First, you already have an ADR regulation, and it hasn't been in the regulations for a very long time, but it has been used. I think it has been used effectively. The case isn't over yet, but I note that it was used by HillCorp and several other shippers in a matter even before any tariff filing or complaint proceeding was filed with the Commission. So far I've heard that it is looking like it was a productive use of time and resources.

So you already have an ADR process, and it's available to QFs and utilities that are dealing with QFs, so there isn't need to craft a special new regulation for independent monitor and mandatory mediation that applies only to qualifying facilities. Your current ADR regulations will be helpful.

Secondly, AEP's regs are compulsory. It's not ADR. It's not voluntary. It's mediation that's nonbinding, but the utility is required to participate, and it's a long process. It could take almost as long as the statutory timeline for adjudicating a formal complaint.

So the utility would be compelled to participate in this process with the monitor and a recommendation would go to the Commission. The Commission may ask more questions. The monitor can seek discovery, and then the Commission issues a recommendation that neither the utility nor the QF is obligated to abide by.

That seems overbearing and unreasonable and not something that would help the process. To pour salt into the wound, AEP would then require the utility to pay all of the costs of this independent monitor, and the independent monitor's obligations under this regulation are significant. It's a big job, what that monitor would be doing. They would rightfully want to be paid for their time and services, and the utility would be required to bear all of the costs. The QFs would bear none of those costs. The QF would only bear its own costs.

So APA's main problem with this

is it imposes an unreasonable mandatory burden on the utilities, but, secondly, it creates a huge incentive for a QF to demand this process every time. It doesn't cost them anything, and you can immediately bring in a monitor that the utility has to pay for and if you like the result of it and the utility ends up agreeing with it, great. If you don't like the result of it as the QF, you say no thanks; we're going to file a formal complaint and do this differently. So it creates a very one-sided, unfair burden and a perverse incentive to seek this process all the time.

Finally, the justification -- and I think AEP is -- I don't mean to be derisive. I think AEP is trying to get a process that it thinks will improve its circumstances that it has experienced. I will say that for all of the regulated utilities there are in Alaska and all of the proposed QFs that have talked with utilities to try to determine project feasibility, it's very rare that you have complaints filed with you in these matters, which is as it should be. I mean, you're here to resolve complaints about the scope and effect of regulations. It doesn't happen really frequently, but when it does, you issue your decision and the parties can move on. If the parties want to do that process faster and cheaper, then they have the ADR option. But this seems to be a solution in search of a problem that APA believes that you should not undertake.

Lastly, the issue of technical workshops. I apologize that I, on behalf of APA, may not have explained what APA was proposing effectively, because I've heard parties today interpret that as a delaying tactic or that we would be proposing that studies be done simply to delay your issuing a decision and getting regulations in place. I hope the Commission understands what APA was suggesting.

APA has participated in technical workshops in rulemaking dockets to come up with regulatory changes that parties may need and that can make sense in a way that allows all of the parties to come to agreement on a change. It's not a delay tactic; it's a tactic that APA has found to be very successful in getting parties with divergent interests to find some common ground on some issues.

I gave the one example that if the Commission does want the preamble language, it makes sense for the parties with divergent interests to see if they can come up to agreement on that. Commission staff usually participates. APA's experience has been that it's been very helpful to all parties concerned. I would cite the Commission's docket adopting net metering regulations and net metering interconnection requirements where there were technical issues and different perspectives and different goals the different stakeholders were seeking. We were able to reach some compromises that seemed to work.

So if no one wants to participate, APA's feelings won't be hurt, but we suggest it as a way to try to find agreement on some of the issues in this case. But if the Commission doesn't want to go down that path, APA will participate in whatever procedures the RCA does adopt.

I will say, though, that I was a little taken aback by AEP's slide that says you need to just get these regulations passed. I think the slogan was regulate now, implement later. I guess APA would caution you that doing it that way may make for poor implementation. If you don't get it right when you're adopting the regulations, you can't leave it to implementation to correct any errors that were made in the regulation itself. That's why the Administrative Procedures Act, among other reasons, requires all of the processes involved in these rulemaking dockets.

So I understand the need for speed on anything that anyone is requesting of the Commission, but for the reasons that I discussed earlier, mainly protecting the customer from unintended rate and cost increases associated with some of the regulations that are being proposed, APA thinks you should take your time and get it right.

As I indicated at the beginning, APA believes that the best decision overall, all things considered in this case, is to not adopt any changes to the current QF regulations.

ALJ ROYCE: Thank you, Mr. Thompson.

At this time we'll take a break. We'll be back at 3:15. We'll see if the Commissioners have questions for Mr. Thompson or proceed to the presentations by GVEA and ML&P. We're off record until 3:15.

(Off record.)

ALJ ROYCE: We're back on record at approximately 20 after 3:00 for the continuation of the public hearing.

Mr. Regan, are you ready to make a presentation on behalf of ML&P?

MR. REGAN: I am, Your Honor.

ALJ ROYCE: Please identify yourself for the -- go ahead.

MR. REGAN: My name is Bob Regan. I'm speaking here for Municipal Light & Power -- or Municipality of Anchorage d/b/a Municipal Light & Power.

It's pretty clear to me that there are broad areas of agreement between at least ML&P and AEP about the meaning of PURPA. In fact, I'm not sure that I can think of any disagreement we have with them about the meaning of the law. We do disagree -- as explained in considerable detail by Mr. Thompson, we do disagree about implementation, but I wouldn't be surprised if we and AEP were able to agree on regulations if it were necessary for us to do so.

In this testimony I want to discuss only one thing, and it is -- it's the assumption by AEP and other proponents of QF power that incremental cost is always and obviously higher than average production cost. The fact is incremental cost can be higher or lower than average production cost. One of the characteristics of the utility industry, in fact, is that it's a declining cost industry in general, and declining cost implies incremental cost, below average cost. I'm not claiming that as a general rule for avoided cost, but it's a distinct possibility.

So, anyway, I want to just describe in vastly oversimplified terms how dispatch works and what the implications of the workings of dispatch are for the relationship between incremental cost and average production cost. This is actually -- it's not a slide show. It's an active Excel workbook, but we're going to go through it pretty much as if it were a slide show. I'm just going to go across the headings and talk very briefly about each column.

ALJ ROYCE: Excuse me, Mr. Regan.

MR. REGAN: Yes.

ALJ ROYCE: Are these slides available on any type of copies or PowerPoint to distribute?

MR. REGAN: I have eight hard copies of each one of the worksheets that I expect to show. They're not labeled in any way, but you're certainly welcome to them.

ALJ ROYCE: Would it be helpful for the Commissioners to have a copy? I know the court reporter would need a copy if you can --

MR. REGAN: It's fine with me. In that stack right there they are sorted by the sheets, so you've got to give one of each to each person. Yeah, I'm sorry.

ALJ ROYCE: Please continue.

MR. REGAN: Okay. Just going -- well, first of all, that little block to the left with the word "gas" at the top of it, that's a very small assumption block; that is to say, it's assumed values for variables that are used in calculation of the quantities in those columns. I do not -- I think you should ignore it. I mean, understand that it's there. Understand that the assumptions there are arbitrary and not necessarily intended to reflect any actual reality. They are somewhat close to the cost that ML&P experiences, but certainly not identical.

Looking at the title of this table, it says "Unit 1 Costing." Unit 1 is ML&P's oldest and smallest turbine. It never runs, so the costs that are reflected on this table are not relevant to any actual calculation of avoided cost, but they do show similar characteristics to the cost of most of our turbine generators.

The purple column there that says "Megawatt Hours Per Hour," you can think of that as megawatts, but just as an aside, dispatchers think in term of megawatt hours per hour; they think in energy terms rather than power terms. But for each individual hour it results to the same thing either way. So this just goes from zero to maximum output for the turbine, and this turbine only goes to 18 megawatts.

The next column to the right, "MCF Per Hour," that's MCF of gas per hour to produce whatever amount of energy per hour is in the left-hand column. One thing I'll point out about this is notice it's not zero for zero megawatts. It's 84 MCF per hour for zero megawatts. So there is a zero intercept on the cost curve. That is typically called the speed no load cost, which I'll show in the next slide.

The next column over is "Dollars Per Megawatt Hour." That is average cost. That's the total cost of operating the turbine at that level divided by the output. The most important thing to notice there is that it starts very high because of that speed no load cost, and then it declines continuously throughout the range of operation.

The next column over, "Incremental MCF Per Hour." Not much to say about that except that the cost characteristics of that is that the -- let me say the incremental cost in mathematical terms, it's the derivative of cost with respect to output. In economic terms you'd call that marginal cost if it were for an arbitrarily small increment of output. We use the discrete term incremental cost because it isn't necessarily an arbitrarily small change in output.

The important characteristic here is that it starts quite low compared to the average cost of production. At 1 megawatt the average cost is 365 -- well, let me say the average cost in MCF is 91, whereas the incremental cost is only 7.27.

Moving on, the column that's

called "Lambda Gas." Lambda there, again, you can think in terms of DYDX. It's the derivative of the cost curve, and it shows the same characteristic as the incremental MCF for megawatt hour -- or per hour.

"Gas Cost" is Column D, I think, multiplied by gas price. "Total Cost" is gas cost plus the variable O&M cost, which we assume there is $2.26 per megawatt hour.

The last column, "Total Cost Per Megawatt Hour, Gas," that's basically the gas cost per megawatt hour plus the variable O&M charge. The value at the top -- it's in red. How do I describe that? That number would be undefined at zero output. This was calculated at 0.3 megawatts or 0.3 megawatt hours per hour. Really the only reason I put it in there is to make a picture that will show up later a little more interesting to look at.

We could go to the next -- let me stop and just say, if anybody has any questions, it's probably best if you interrupt me and ask them as I go. Let's go to the next sheet.

This is a speed no load chart. All it does is show you in dollars using that $4 per MCF assumed cost of price of natural gas. This is what it costs to run a turbine synchronized to the grid at no load. So to produce zero energy, but to be available to produce energy. Unit 1 that we were just talking about costs, you know, what, $330 per hour to run at zero output. Our biggest unit, Unit 7 and combined cycle, that's really the Unit 7/Unit 6 combination, costs almost $1,000 -- $900 per hour just to run at zero output. It's important because it explains the reason that incremental -- incremental costs can be below average cost.

I guess we'll go to the next slide. Okay.

This is just a picture of what I showed you before. The blue line is the total cost per hour to run the turbine at outputs as displayed on the X axis. So it starts at intercept at just above $300 an hour. Let's call it $300 an hour at almost zero load and goes to a maximum of just over $1100 an hour, producing the most power that

that turbine is capable of producing.

The red line is the cost per megawatt hour. The most interesting thing about that cost is that it starts very high and declines throughout the range of operation.

Now, something that I am going to ignore in my discussion, but you'll probably hear about from Golden Valley, is that nobody actually operates turbines at very low load. Every turbine has some load below which its owner will not operate it. I won't say any more about that, but I'm thinking that Mike will say some things about that.

The black line is the incremental cost at each output level for that turbine. So it starts at -- I don't know -- a low number that I couldn't even estimate looking at that scale and gradually increases until it basically equals the average cost per megawatt hour at maximum output. That's a typical pattern for turbines. They don't all have an identical pattern to that, but you can think of that as probably the norm.

Next sheet. So this is just a

top of my head list of real-world constraints that I will not be considering as I talk to you, but you will hear more about probably from Golden Valley.

So the first one of those constraints, minimum output, all I'm telling you is that there is some minimum output for each turbine. I don't know what it is, but I do know that dispatchers do come up against those constraints from time to time. Right now ML&P and I think the other Bradley Lake owners -- I'm sorry -- purchasers are doing everything they can to draw down Bradley Lake. Most of them are running into minimum output constraints on the thermal generation that they cannot avoid running. So that's a real issue.

That second issue, that second constraint I have there, startup time, all I mean by that is that it takes a significant amount of time to start a gas turbine. If you ever fly in turboprop airplanes, for instance, you'll see that it takes them, you know, a real finite amount of time to get those turbines spun up. These industrial turbines take much longer in general than those aircraft engines, although the aero-derivative engines that have become popular just very recently do start a lot more quickly than the industrial turbines we're more used to.

But the reason that that's there is that if we are talking about nonfirm power, utilities don't just sit there with a dispatcher with a bunch of turbines on the shelf deciding which is the next turbine to deploy as loads or as net loads go up and down. That dispatcher has to have everything he's going to use, let's say, during the next hour. He's got to have it running well before he needs it.

So if your load goes up a little, and in theory you could start a turbine that had lower total cost for the load you need out of it, but that turbine's not running, too bad. You're not going to start it.

Go down to the third real-world constraint, start cost. That's one of the reasons you're not going to start that turbine, other than the fact that it takes time to get it started. You burnt some fuel starting that turbine and not producing energy. That startup cost also varies depending on the turbine. I think the aero-derivatives have almost negligible startup costs, at least in gas terms. The frame turbines definitely do not. You know, their startup costs could equal -- I think it could easily equal a half-an-hour worth of speed no load cost. So you could spend in some cases $1,000 just to get a turbine started.

So you don't -- you know, you try to minimize turbine starts; I guess that's all I'm saying. You don't figure you're going to start it up six times a day. You try to start a turbine once, run it for as long as you're going to need it, shut it down. Maybe you would start a turbine twice in a day, but you might not be too happy about that.

No. 4, minimum downtime. This is something I don't know much about, but once you shut a turbine down, you can't immediately restart it. You've got to wait for it to cool down. I don't really know how long minimum downtime is for various turbines. This is something you might hear about from Golden Valley. It's a significant amount of time. Once you shut down a turbine, I don't think you expect to use it again at least for an hour.

Finally, ramp rate. That's just the speed with which a turbine can change its output. The reason that's important is that some turbines are not very useful for following variations in load. They just can't respond fast enough. Other -- so you might well be using a turbine that's either more expensive or less expensive than your average to follow load or to follow net load just because the lowest cost turbine or the highest incremental cost turbine won't do the job.

One final remark about complications. The incremental or decremental costs, I'll just call it marginal cost now, although that's not strictly a correct term because it's continuous, whereas incremental and decremental is discrete. But marginal cost is not a constant with respect to either output level or the change in output. I think you will hear some about that from Golden Valley too.

In what I'm going to talk to you about everything is with respect to a change of 1 megawatt in output. Clearly, Golden Valley has to consider dealing with changes as great as 25 megawatts, and that's a different issue than 1 megawatt by a large amount.

Okay. Actually, now that I think of it, go one more. Okay.

This is a table, and it's much wider than the screen, so Anna's going to have to scroll through it from left to right. So go all the way left now. This is a table of a dispatch that ML&P actually experienced in one day in 2012, and that I think was a Sunday, January 1st. At the end of the day it turned out that the various units produced the power that's shown there in the hour shown. So the column on the left is the hour of the day. So that 1 stands for 0100 on that Sunday morning. U-1 stands for Unit 1, the unit we were just talking about. The numbers in that column below the unit number are megawatt hours per hour. You could think of that as megawatts that the unit actually produced.

So what you see here is that Unit 1 didn't run that day and, in fact, probably didn't run at all that year. Unit 2 didn't run that day, and also probably didn't run at all that year. Unit 3, which is a simple cycle aero-derivative turbine, it's the newest turbine that ML&P owns 100 percent of, was used basically to cycle for a block representing peak load. But note that for some reason or other they block loaded it rather than following load with it. In hour whatever that is, 0900, they started the unit and they ran it at maximum capacity until hour 2300 when they dropped off to 26 megawatts and then they shut it down.

I'll back up just a little bit and describe the dollars per megawatt hour column for each one of those units. That is the average production cost per megawatt hour for that unit. Since Unit 3 here was running at essentially full load every hour, that average production cost was very close to being a constant.

The columns that are labeled "Delta Over Delta" are the columns for that unit for the price you could -- well, actually it's for the extra cost to increase output by 1 megawatt. Although in this case that unit was probably running at maximum -- well, I think it could maybe put out more than 29 megawatts, but I'm not sure. But it's probably that was just maximum output. So you could think of that $36.66 as what you could save for a decrement of 1 megawatt in that hour at that load.

So moving to the right, Unit 4 didn't run at all that day. Not too surprising. It's one of our older turbines.

Scroll so that we can -- yeah, stop there. Unit 5 didn't run at all that day. The Unit 5/6 combination, that is to say, it's a combined cycle combination. It's Unit 5 providing heat to steam turbine Unit 6 ran at its maximum output all day; therefore, had basically a constant cost per megawatt hour and a constant decremental cost, the decremental cost in that case being $38.21.

Unit 7 didn't run at all in simple cycle that day. The Unit 7/6 combination ran all day at a fairly high load. That's not its peak load, but it's fairly high on its output scale, and at a constant enough load so that you don't really see any variation to speak of on its cost per megawatt hour, and you don't see anything to speak of variation in its decremental -- well, in this case it's really the incremental cost. It stays pretty constant at about $35.60.

Okay. Let's scroll to the right probably to be able to see the rest of it.

So Unit 8 didn't run at all. That's typical. Unit 8 is a big simple cycle turbine, and it costs quite a bit to run.

Now we get to Eklutna. That is a hydroelectric project, and we run into our first conceptual problem. What is the value of hydro power? If you're calculating average cost -- average actual accounting cost, I guess the value is zero. I'm willing to admit to you that we don't think of the value of hydro power as being zero. That value is an opportunity cost. It is the value of the most expensive other power that you think you would be able to displace with that hydro output if you saved it for use later.

What that value is going to be depends on a whole lot of things. It depends, for instance, whether you expect the project to spill during the period before you would get to use it for something high value. Now, a spill for a hydroelectric project just means instead of running water through the generator or through the turbine, you run it over the spillway. It wastes the water from a utility's point of view. It can be affected by other constraints too. I'm just saying it's a complicated problem trying to forecast what that opportunity cost of water is.

In this case I made the completely arbitrary decision that it's worth $21.98 per megawatt hour. In a real avoided cost determination, I guarantee there would be argument between the utility and the QF over the assignment of value to hydro power. I don't represent that this roughly $22 a megawatt hour is the right number. I just threw it in there because it makes the pictures possible.

I can say that it's pretty much certain not to be above $45 an hour -- a megawatt hour for us. It can be as low as zero. It changes not necessarily all the time, but it does change.

Next column -- oh, and the other thing I'll say is note that on Eklutna the outputs are changing every hour. The reason for that is that Eklutna is what we used that day to follow our variation in load, and that was not based on any conventional understanding of the incremental cost per megawatt hour. It's based instead on the fact that hydroelectric power works very well over a very broad range of outputs and is therefore convenient to follow load with.

Now, there's a value to that, and I don't know how to quantify that value for you, so I'll leave that at that.

We did not use Bradley at all that day. I'm going to assume that the reason for that is that Bradley must not have been available to us that day. I think almost certainly we use Bradley at least to some degree on any day that it's available to us. That's partly because, like Eklutna, it's pretty handy for following load with, and like Eklutna it has the potential to spill and you don't want it to spill because that's just throwing dollars over the spillway. So I'm guessing Bradley was not available that day.

Moving to the right, then, we come to a column that says "Dollars Per Hour System." That is the total cost of operating the system to produce power in that hour. I'll just remark that it's assuming that your hydro power is worth about $22 a megawatt hour, which easily could be the wrong assumption.

The next column over, the delta over delta column. That is the delta over delta for the highest incremental cost turbine that was available to us to back down during that hour. So if you took that $38.21 and you looked at all the columns to the left, you'd find one associated with some turbine. Probably I'm guessing it would be the 7/6 combination. Why don't you scroll left and see that. So 7/6 -- it's not 7/6. Yeah, it's 5/6. So that's the turbine that, according to that conventional understanding of incremental cost, determined the incremental cost for that hour.

Moving to Column AL, "System Megawatt Hours," and that's per hour. That's just the system output during each of those hours. So it varies from, I guess, about 143 up to 186, which is typical for ML&P in the winter.

The column next to it, that's our average production cost per megawatt hour in that hour.

Finally, we have another column labeled "Delta Over Delta Actual." I will tell you how that's calculated, and then I'll admit it's not really an actual delta over delta either. We can discuss that in a second. But all I did there is for each hour

I calculated the amount by which output changed from the hour before to that hour, used that as the denominator, calculated the change in cost per hour, used that as the numerator, and divided one by the other. The reason that that's not really a delta over delta with respect to output is that there are so many other large variables that drive those changes in cost that are not change in output.

Now we can go to the next -- go back one to the chart dispatch January 1. If you look over towards -- okay. Let me just say the red line -- the columns are megawatt hours of dispatch, and the different colors are just which unit was producing the power. I didn't make any effort to be consistent about what color is what unit, and I don't think you need to worry about that.

The lines are some representation of unit cost. The red line is the average cost per megawatt hour during that hour. The blue line is the delta over delta for whichever unit had the highest delta over delta in that hour. It is, in fact, very slightly above the average cost line. So if you take that blue line as the representation of incremental cost, then it is in fact very slightly above average cost. The thing I would want you to keep in mind, though, is that's a really small difference and it doesn't have to be in that direction, although for our system in 2012 it apparently was usually in that direction.

The black line that goes all over the map is that last line that I described to you, which was changing cost divided by changing output from one hour to the next hour. One of the interesting things to notice is if you look at hour No. 22, you have an extreme dip. If you were to look back at the dispatch curve, you'd see that there wasn't really a very big change in cost that hour. The reason it looks so extreme is that there's almost no change in output in that hour, but we made some change in dispatch. I don't -- I can't identify it right now. But that -- so that's a place where that estimation of incremental cost using that method really shows effects that are not incremental cost with respect to output.

I don't think there's anything else that I need to show you. Anna, what we'd like to do now is just look at each of those chart dispatch -- those dispatch charts. Yeah, that one.

This is the same thing for the next day. I apologize that the colors are not necessarily consistent. Part of the issue, if you were to look at the legend, you'd see that there were actually different units dispatched on that day, which would complicate the issue of trying to maintain color consistency. Again, we see another one of those extreme dips not associated with any large changing output.

In that one we can clearly see that the dispatch change that's related to that is we started -- let's see. What did we do? We started Unit 4, and right off the top of my head I can't tell you why that would -- oh, and what's the blue one? The blue one is Unit 3, and I don't -- oh, okay. This is really paradoxical, and I guess it is worth you knowing about.

In this case we made a change in dispatch that clearly reduced our overall cost. We shut down Unit 4, which is a relatively -- I'm sorry. We started Unit 4, which is a -- so we increased cost. We started Unit 4, which is a relatively high-cost unit and we shut down Unit 3, which is a relatively low-cost unit of roughly the same size.

The reason that it shows that big dip in incremental cost is that that increase in total cost was associated with a small decrease in total output. So it produced really a counterintuitive and really spurious result. The only reason that I call attention to it is to show you how difficult it really is to develop an algorithm that would reliably produce an incremental cost. I'm not going to say it can't be done. We can come up with various algorithms to do it. The real trick is to get our counter parties, in this case AEP, to agree with us about the modeling we did.

I mean, I guess what I'm arguing

here is that when we say the modeling is difficult, we're not really saying we can't do the modeling. What we're saying is we can't necessarily persuade the other side that we did it right.

I think I -- I guess that's all I really wanted to say. So I'm proud of myself for keeping it short.

Are there any questions?

ALJ ROYCE: Thank you, Mr. Regan. Are there any questions by Commissioners?

COMMISSIONER PATCH: No questions.

ALJ ROYCE: Okay. Thank you, Mr. Regan. You are excused.

We'll next hear from Mr. Wright and GVEA.

MR. WRIGHT: Good afternoon. My name is Mike Wright.

ALJ ROYCE: Hold on a second. Make sure your microphone is on.

MR. WRIGHT: My name is Mike Wright with Golden Valley Electric. I'm the vice president of transmission and distribution.

ALJ ROYCE: Excuse me. We can hear conversations, whoever is listening on the phone. We can still hear you.

MR. WRIGHT: All right. So now we can get started. So I want to start off, and I'll go really quick through this part so we can get to --

ALJ ROYCE: Excuse me, Mr. Wright. I think we have some IT people here if we want to -- what he's trying to do is maximize the screen.

MR. WRIGHT: Thank you. So I'm just going to start quickly and go through this part quick and get to the meat of it.

But Golden Valley does have a commitment to qualifying facilities, and we have had that for quite a number of years from Bradley Lake to the board's renewable energy pledge to our SNAP and SNAP Plus -- homeowners put renewable energy into the system -- our experimental renewable resource purchase program that we have, and then our own Eva Creek wind project.

SNAP and SNAP Plus, SNAP Plus is essentially net metering, but there's also --

we allow members to pay in and contribute to that. It gives more incentive to the homeowner type renewable generator, and then we also have -- and there's 42 of them on the system, 36 Snaps at this time, which are generation only.

Essentially, we use the regulations that they're asking us to revise to set up guidelines and reasonable nondiscriminatory charges, rates, terms, and conditions for interconnection. Those came right out of the regulations, and we think that they don't need to be changed. They're especially appropriate for the smaller generator.

One of the points I wanted to bring up, and if you remember when we dealt with net metering, we set a limit on 1.5 percent of demand for penetration for net metering. The reason we did that is we are charging no special costs to the net meterer until such time as it could cause an impact to our system. At that point you would look and see if net metering is causing an impact, and that would be because the variable may potentially have solar cells or small wind projects, but then you would evaluate it at that level. So I just want to make that -- raise that point.

Then we have our experimental renewable resource purchase program. We actually have two people on that. We have -- AEP has a 2 megawatt wind farm down in Delta that's participating in this, and Bernie Karl has Chena Power that's right in town that's a waste burner that's participating. It has a 2 megawatt limit. You're interconnected at the distribution level, so it's not a large megawatt scale that would connect to our transmission level.

As the title points out, it's experimental. It allows Golden Valley to evaluate and analyze how these types of -- this size of project affects our system. The key I want to make here is the fourth point, is GVEA is absorbing the integration costs at this time. If you go to our QF rate in tariff sheet -- and I happen to have it with me, so if you want to, it's sheet No. 120 in our tariff. There is a line on it where we will go less integration cost including voltage regulation. Right now we charge zero for that, but that's because we carry a certain small amount of regulation at any moment for our system. Right now we only have the 2 megawatt and Chena Power is about at most 500 KW, if they ever get it up and running and they're having issues and they're working their way through it, but it hasn't fully established itself. But there could get to a point where it would be significant enough that we would have to factor in integration costs, but at this time we charge nothing for that.

Once again, we established a set power sales agreement that established guidelines at the reasonable nondiscriminatory charges and stuff based on the small generator regulation. So that's what we went in there and we have that in our tariff also. It truly streamlines the application process. It streamlines the interconnection process. Once again, we are absorbing the integration costs; Golden Valley absorbs at this time.

Then greater than 2 megawatts. The project we have right now on our system is Eva Creek wind project. One of the points somebody brought up earlier that I'd like to correct is with Eva Creek on our system and Bradley Lake, that's 20 percent of Golden Valley's nameplate capacity at peak demand. It's about 13 percent of our total energy. In the summer during our valley conditions in the summer, Eva Creek is actually 25 percent penetration. So with Eva Creek and Bradley on the summer, which would be late evening with Fort Knox off line, which happens from time to time, it could be up around -- 40 percent of our generation could be renewable at a particular moment, but certainly up to 25 percent with Eva Creek.

So we do have a significant penetration of renewable energy and wind energy on our system right now. They made it seem like it was a small number. It's actually a large number for a system that is not interconnected with the grid. Like in the Lower 48 you have many, many balancing agencies, a total interconnected grid. We're kind of like an island. The only people -- I would say utilities that experience the same issues we have would be like Kodiak with its wind or Maui Electric. But we are not interconnected with the grid, so we have significant issues that are -- they're the same issues, but they're more significant with us because they're so small -- because we're so small.

The reason I wanted to bring up here -- and there's a lot more to the evaluation. We evaluated two other projects when we looked at doing our own Eva Creek project. We did quite a few years of study and I gave presentations on that before, but one was CIRI's Fire Island project, which actually came in at a fairly competitive price. The challenge with them was is they're so far from our system, we had wheeling over a long distance and the losses put them above our Eva Creek price. Then we did have -- Delta wind gave us a price locally, but their price was significantly higher than what we could have done for ourselves.

I just have a couple of the items in here to look at, but we looked at wheeling. We gave credit for losses. If you look at Delta wind farm, they're on our system and some of their power, it would reduce the amount of power that went to Delta. We gave them a credit on our evaluation, our final evaluation. They got some credit for that, where Fire Island had losses and we evaluated it at Eva Creek. That was the point we evaluated it, so there was no losses with Eva Creek.

The regulation price we have on here, you can see we charged ourself a regulation price and essentially that's an integration cost. We charged ourself that. Fire Island's is a little higher. That was based on some of the issues that were going on in Chugach now, but even if it was -- we just would have put it at our same price with the wheeling and the losses to bring the power up to our system, that's what really priced them out of the range of our own Eva Creek project.

I did get a number. I didn't

write it down. I got it yesterday. I asked what our 2013 first year full operation, and it actually is right at about 9.53 cents. So it's actually a little bit less than when we did our evaluation on our project in about the 2011 time frame. But we looked at it. We evaluated it. It was just like we would do any project and we didn't -- there's no discrimination or anything in here. We looked at everything equally, an apples to apples evaluation at that time.

So now we've dealt with -- we've actually dealt with two PURPA QFs and both wind projects since that time. One didn't bear fruit and didn't even go anywhere. It was AT&T looking to put a 50 megawatt system somewhere down south of Delta. They started working with us and we did some studies on that, but then they dropped it because it wasn't panning out for them.

But there are the four issues that we are looking at right now that have been raised by AEP in this public hearing: Avoided cost, integration cost, curtailment, and interconnection costs. I'm going to go through those. But first I want to make sure we're all on the same page, and I think we are relatively on the same page from the discussions today, so I won't spend too long on interconnection, integration, regulation, and curtailment.

But interconnection, it's simply the cost of connecting a QF to our system. The regulation already says a utility may assess qualifying facility interconnection charges. In general, QFs greater than 2 megawatts would have to be connected to Golden Valley's transmission system. So that would require transmission line and either the addition of a transmission substation or expansion of a transmission substation. Those are fairly significant costs. In this case we shared that estimate with the parties that were dealing with us. We would share that. We've done several of these. They're not discriminating.

We did the same charges to Pogo Mine when they tapped into the transmission, when Fort Knox built their system. We have a thing on the street right now with Clear Air

Force Station. If they move forward, they'll have to pay the interconnection cost the same as a large megawatt scale wind project or a coal plant or anybody who would attach to our transmission system.

So it's -- we have good experience with that and have done about seven of them over the last ten years of these substation expansions and interconnection with our transmission facilities. So it will be easy to show our estimates. It really comes down to the actual cost, final cost. If our estimate is a little high, if it comes in less, they get charged the lesser price. So it is nondiscriminatory.

Regulation. I have to admit, I have learned a lot over the last years on this, our experience with Eva Creek and just wanting to come down here and make a presentation. Regulation is -- and sometimes regulation and integration gets intermingled, and it's not the same thing. I learned that myself, and it took me a while to figure it out totally.

But regulation is providing the continuing balancing of resources, basically generation and load, and it's a capacity cost. It's a cost per KW, not an energy charge. Unless you had to add generation in order to integrate the wind, there's normally not much of a regulation charge that's charged to adding a wind project or a QF project to your system. But if it was, it would be a capacity cost, not a per kilowatt hour cost. That's not regulation.

Integration costs, however, is simply the cost impact of a nonfirm resource through its variability and uncertainty. I got this right out of the NREL report that I could dig up and get the information, but I took it out of there as I'm learning about this. Basically the cost due to decrease due to deficiency, due to more frequently ramping and operating at a less efficient point on its heat rate curve. There's also costs due to increased wear and tear due to the cycling on the system.

The energy cost, it is an energy cost, and it's in dollars per kilowatt hour.

That is the cost that you would decrement more than likely. You know, there could be an increment, but a decrement or increment to your avoided cost.

Curtailment. That's simply reducing the wind production when the production exceeds the system's capacity to safely absorb the power while maintaining adequate reserves and dynamic control of the system. So there's just sometimes when you cannot as a utility absorb the wind and keep your system -- hold the system together or have the reserves you need to operate your system adequately and safely.

So what we believe is that the regulations are essentially the same as the FERC regulations, and they don't need to be changed. There's two approaches to curtailment. If power is on an as-available basis with price determined at time of delivery, then curtailment would be possible if purchasing the power would result in greater cost. Essentially what that comes down to, and I've heard the argument today -- and, like I say, I'm always learning.

If it came to the point that it was costing us money, then the actual incremental cost of that wind would be negative, and the QF would want to come off line. So whether we curtailed them or not, they would be losing money if they stayed on line, because the only way it would be raising our cost is if the incremental cost was basically going to a negative value right then. It could be that the price would just be so low they wouldn't want to operate. That would be their choice, but if it was going to cost us money, that would be a negative incremental cost. I have to think about that more, but it shouldn't be that it costs our members money to take power on an as-available basis.

If the power sale is by a long-term contract that's a predetermined price, then the utility may be responsible to pay for curtailment. When I say "may," there's a slide later on that I'll show why I'm saying that. The real answer is we -- by the FERC requirements we would, but when you see the slide I have later, there could be a financial -- the value of the wind could be such that the QF is making more money by allowing us to curtail and keeping the value of that wind resource greater. They'd actually get more money by allowing us to curtail when it would cause a negative effect on the system. If we're forced to take all the wind and pay for all the wind that that resource could generate, then it will lower the value of that wind and they could end up with a less value. It would -- the incremental cost would be less, and they may not make as much money.

So it could behoove them in their negotiation to say we're willing to do X amount of curtailment, and then after that, you have to pay for any additional. Once again, that can be negotiated and you go and see how that cost varied the price we're willing to offer on the long-term contract.

So we're in agreement with what everybody has presented. I don't want to take this venue to talk about our negotiations. This isn't about our negotiations with AEP last summer, but they did bring up that we made an offer that diverted from this and that -- from our perspective at Golden Valley, that is not accurate. With we first discussed with them -- and I want to leave it at that -- there were two paths we could go down. They did make time of the essence; it was important to them we said. We recognize we have to take your power right now on an as-is basis, and we are making -- but they still wanted a long-term agreement. There was no price in this agreement. It was an agreement to take it at our QF rate, whatever that would be, and that's basically an as-is basis, so we put in an integration cost. You had the available power cost, and then we just put in the right to curtail if it was going to cost us money to take their power. So essentially it was a long-term agreement, but it was on an as-is, as-available basis for power. It was not a negotiated price.

We recognize -- and then we were going to negotiate the other side of the equation, which was to negotiate a long-term agreement. The negotiations broke down. We didn't go any further. But in the long-term agreement, that would have not been part of the agreement would be a curtailment, unless it was agreed to that it was financially beneficial to both sides to go ahead and do the curtailment through operating efficiencies and making that wind more valuable.

Just to show you -- and this is just a snapshot of our SCADA system. In the red block down here you can see -- I mean, the gray block with the red and the green. The green's our wind speed. The red's our power output. At that particular moment on our system we had to curtail our wind, and we curtailed it at 18 -- up there it says power curtail, 18 megawatts. So at this particular moment, even though we could have put out 24 megawatts, we had to limit Eva Creek to 18 megawatts.

If we had 50 megawatts, so if there was a second wind farm producing or if our own wind farm was at 50, we would still have had to curtail it to 18 megawatts. Curtailment is a real issue on a small system such as ours to make sure it stays reliable and we don't have issues at any moment. There's been times we've had Eva Creek curtailed to 10 megawatts and lower numbers, but this is just a snapshot at one particular moment. So curtailment is real. We have to curtail our own system.

So we'll go into the real cost of integrating nonfirm power here. So avoided cost and integration costs. Those are the two components. One of the presenters today mentioned, and that's how we would approach it also. If we approached a long-term contract, you would calculate in the integration cost to the price you would offer them, and it would be an incremental cost that included the cost of integration.

You would have -- and I just learned this through our discussion today. It became kind of like an epiphany. You have an integration cost as a separate cost if you have a standard offer. Your standard offer already sets a price, but as you add more and more wind, and if you've dealt with the Idaho case or many other things, the more wind you add to a system, your integration costs rise exponentially. They're not linear. So the more you add, the more it goes up.

So you have to have the ability -- and then if you have a long-term contract with person No. A -- entity No. A and you've already settled in that -- and I'm making these -- 7 cents a kilowatt hour and 1 cent integration, you can't go back to that 25-year contract. Now you've added another wind farm and your cost of integrating wind goes up to one-and-a-half cents, you can't go back and go, I need to raise your rate to one-and-a-half cents. You need to charge this group that's the new group the full cost of their incremental cost of the rise in cost of integrating that new increment of wind. So you might have a standard offer, but their cost of integration is a little bit more, which would decrement their total price.

So I see that. So what our two approaches would be, an entity could purchase our power at our QF 2 rate on an as-available basis, and our QF tariff would be the avoided cost, but what makes it incremental is the integration costs. I do go less integration cost. If the integration costs were such that it was -- saved us money, then that would be an adder to it on an incremental basis. So if the value of the wind was such that it saved us money, then we could actually add a little bit of money to it, and that's how it would go if you were doing it on an incremental basis. Or you would do a purchase of the QF by special contract, which is already allowed under the existing regulations. That would be a long-term contract.

We would calculate our integration costs into the purchase price, and it would be based on avoided cost methodology and actually be an incremental price, not an average production cost. It would turn out to be an incremental cost.

So I'm just using a quick example. It's one of the reasons why I think workshops would be valuable, or potentially valuable. I'm just saying the method I'm going to go through here is just for one hour. To really come up with your cost you're going to offer, you do that for a whole year of production modeling. Parameters would have to be agreed to, and we'd have to go through and show how this works so other entities would understand.

This is -- and accept that from a utility's perspective, this is how we have to dispatch our system. It's not always the most expensive power that is cut out of the system. So when our incremental -- and how to develop our incremental cost.

I wish I had brought a pointer with me. We're basically get 64 megawatts, which is in the bottom, from Anchorage. The green block on Healy over there in the lower left-hand corner, we're doing -- 26 megawatts being generated at Healy. Eva Creek is putting out 20 megawatts. It's actually curtailed at this moment. It wasn't the same picture from the last one, but we had to curtail that at the moment.

One of the key things is -- oh, it's cut off a little bit on this slide. I don't know why. Oh, no, it is. You can see it down at the bottom. The chair is in the way for me.

North Pole -- NPC is North Pole combined cycle. It is down at 32 megawatts or a hair over that; 32 megawatts is the lowest that unit can go in combined cycle. It gets a little bit lower than that, then we have to go to simple cycle. That's a key issue, because when it goes to simple cycle, we have to shut up the back end, the heat and recovery steam generator. The heat and recovery steam generator is free energy. You get rid of that, now you've taken that unit and greatly increased -- its efficiency goes way down the tube, so its cost per megawatt hour goes up.

So for this example -- and the total load in here -- oh, I'm sorry. We are getting power from an IPP, Aurora Energy, another 28, 27 megawatts from Aurora Energy.

So this is a little bit more simpler from what Bob presented here, but this is our power plants that we have dispatching right now. The red circle just shows that Eva Creek is on, and it can go from zero to 25 megawatts. So while that plant can go from zero to 25 megawatts, Golden Valley has to have the availability to regulate 25 megawatts of variability in the system. So we have to have that room available.

We have 41 megawatts available at this moment. So right now we have, just like we had on the previous slide, 20 megawatts at Eva Creek, 32 coming from North Pole combined cycle, 50 from the intertie, including 14 from Bradley Lake, which also comes up the intertie. That makes 64 megawatts up the tie. Healy putting out 26, and then Aurora Energy putting out 25 megawatts.

With their cost of their power so right now at this moment, it's $86 a megawatt hour. That's the cost right at this moment for 167 megawatts of generation on Golden Valley's system.

So what I'm going to do is I'm throwing in a nonfirm QF. We'll just make it another wind project at 25 megawatts, and I pick $125 a megawatt hour just because that's a number that we've received from an entity in the past. So I put a red block around two of our generations. For Healy 1, we had to back that down from 26 megawatts to 23 megawatts. That's reducing our $50 a megawatt hour power. So we had to back that down. You'll see why, because we only can put out 167 megawatts.

Our North Pole combined cycle can no longer operate in combined cycle because it's less than 32 megawatts. So we had to go to simple cycle, and it's down to 10. The reason it's down at 10, it can't go below 10 which is why we had to back Healy down an additional 3 megawatts because North Pole can -- its minimum operating is at 10 megawatts of production. So we had to back Healy down to make room, to have the regulating room and to only put out 167. We can't be generating 170 megawatts with only 167 megawatts of load.

Now, we had other options and that's why it becomes a very deep (indiscernible) process. I didn't do all these, I'll say. But Zehnder, we could have put on a Zehnder unit instead of putting on -- making some variations. But Zehnders in the 3, 4, $500 range, depending where it is on its heat -- its curve. So Healy -- or North Pole 1 or 2, but they're more expensive. So you would look at all the options and then you would dispatch the cheapest power.

What you can see at this scenario, by taking wind at $125 a megawatt hour at this scenario, which was this -- was a December load, a little lower than normal, but still 167 megawatts, which was right around our average for a year. Our average demand for a year is 160 average. It raised the cost of power to 91 from -- what was it. From 86 to 91, so that was a $5 increase, instantaneous cost. So our incremental cost went up, so the value would be essentially decremental in this condition.

But this isn't how you would go and calculate the value of the wind and what you would pay for the wind. I just wanted to show that adding the wind at a certain price doesn't necessarily lower your cost of power.

Well, one thing -- I wanted to go into this. There may be questions of why do you need 50 megawatts of available spin to regulate the wind? You could use less, and maybe you want to be in a risk and you could do without. There's a lot of things that you might do and could be learned over time. But on our system right now there's a possibility that you -- you have to be ready. If the wind goes away, whether the wind drops off or if it's over speed, you lose a line, there's a lot of things that could cause you to lose that generation. Wind is just nonfirm energy.

So what I wanted to show is this is a graph we put together for November. The green power -- I snipped it, so it's not so clear. We could do it better if you need it. But green is Eva Creek. Red is the output of AEP's 2 megawatt wind farm in Delta multiplied by 12. Now, it looks a little jagged. In truth, it would be a little bit flatter. Like the blue line would be flatter, because some of the data we get from when you're pulling off the SCADA system, its timing could make it jump up and down a little bit when it's really more flat.

But you can see that it is -- because -- and I'm not a meteorologist, but it must because it's in the Alaska Range. What we're experiencing at Eva Creek is what they're experiencing at Delta wind farm. There's a lot of coincidence in those two generations. You can see there's times we're getting up and we would have been 50 megawatts of total generation quite often during the month of November. Then you can see that that 50 megawatts of generation goes away, maybe not moment to moment, but on a regular time to time, and it's variable in nature that you could have it.

So it is additive. It doesn't -- there's some places in there you can see it ameliorates it a little, but it is additive. It is not like Delta blows or -- and we don't have one with Fire Island, but it could be that Fire Island and us may be opposed and not additive, but in the case of wind at Delta -- and this is the only example we have of that, because there happened to be a good wind farm down there right now, a 2 megawatt wind farm, but that's why you have to have

50 megawatts of regulated room. It's pretty crystal clear on this diagram.

So what you would do, however, as you were coming up with the value that you would offer in a long-term contract, is you'd come up with the incremental cost of power. The way we model it, and I believe it's appropriate, is we take the nonfirm QF, which is on the first line now, and you put it in at zero. You're charging nothing for it. You see how much that actually saves you.

So in this case if you put that -- and this is just the same thing from the last slide. We put -- instead of $125, we put it in at zero. Now our instantaneous cost drops down to $73 per megawatt hour. So our cost without wind -- without the additional wind -- it has Golden Valley's Eva Creek at 20. It was 86. With the full output of a nonfirm QF putting out 25 megawatts of wind, it goes to 73 megawatt. That's $13 per megawatt hour that we're saving. So that hour was 167 megawatts, so that $13 times 167 megawatts meant that we saved 2171 that particular hour.

What you would do for a whole year is you would take the data that's provided from your -- whoever is -- the entity that's approaching you for sales. They would provide their wind data, and that would be what they say their output was and what their megawatt hours were. You factor that into this. You don't just make up these outputs; they provide it to you. Then you do that for 8760 hours a year, find out what your total savings were, and divide that into your total production. That would tell you the value of the wind. The value of the wind at this moment is $86.84. If I had this as a spreadsheet, if I put 86.84 up there for their value, it would bring you back to that $86 a megawatt hour. So right now the incremental value to pay for wind for no -- for neutral to our ratepayers would be $86.84. That's what we do for a whole year.

We actually did this with -- proposed with a wind project. With a five-year average, what it came in over five years is a value of wind over five years based on information they provided us was if wind was firm, even if wind was firm -- and, remember, this is on top of our Eva Creek energy. We already have Eva Creek on our system, and as you put more wind, the cost integrated becomes exponentially greater, was at $76 for an average five-year average.

If we didn't have to -- if we said we're not regulated, we're just going to take their wind and we don't have to have the regulation to back it up, it could get up to $86. But you can see we also curtailed 15 percent. Almost 16 percent of that power was curtailed at that value. So that's what we paid for the wind that was provided. The five-year average, if we had to provide full regulation, which is the case, would only be $64 a megawatt hour for a five-year -- and that's based on this scenario and these assumptions, which could change now that it looks like we'd have to factor in the potential of LNG lowering the price of our power at our North Pole units and a lot of things like that. But we'd have to look at that.

But what I brought up earlier is

that -- and I didn't calculate this out, but that's $64 a megawatt hour with 15 percent curtailment. If we were not allowed to curtail and we had to pay for the wind we had to curtail, the five-year average would probably be -- well, it would be 15 percent less. We'd have to drop that to $60 or $58, and it could be more because if we have to take the wind, it could change the cost matrix of our incremental costs. So we'd have to do a run and say we can't curtail wind, so what's the incremental cost when we're actually -- there's probably sometimes that there's negative costs. Instead of going zero, it's causing us a negative cost to integrate it into the system. So that's what we -- our approach would be, and we'd do that over five years.

Now, you'd actually do it over 20 years. I just brought -- there's actually more to this, but I just -- for today, I just brought out the five-year average to show that number when we calculated this out. But you would do it for 20 or 25 years. So there would be no integration costs in this, in that your offer would just be $64 or 86 or 76. You would offer that one price for the length of the contract. There wouldn't be a separate integration cost component. It's built into the offer.

So I'm basically finished. I just want to go over some of the key points.

Golden Valley agrees with APA that there's no need to change the current regulations. Avoided cost definition does have the but for and the but for means incremental analysis. That's how Golden Valley was approaching it when we dealt with the couple people we've dealt with, a couple entities for the power. So it's okay from our perspective if you want to add incremental just like it's in the FERC, because it still means the same thing. Incremental but for, and it's the price that you would do if you didn't buy the power from the QF. What would the cost be at that moment? So it's the same thing. So we're fine with that.

An important point. Incremental analysis, as Bob showed this also, but we showed it in ours, will result in reduction of both high-cost and low-cost generation. It's not just high cost -- the highest cost generation, so it should not be presumed to be only the highest cost generation will be reduced. So we totally disagree with that change to the regulation.

The current regulations work well for small power producers, and it includes the ability to do special contracts for the larger producers. So our point, it's working well for our SNAP members. It's working well for some of the small -- we have a couple small cogens I did. Like the food bank has a cogen for heat and producing electricity, and they sell some to us. We have a couple small people like that. It's working well in their case.

It's really like -- I hadn't thought of it before, but like APA, it's a standard offer. It closely approximates it, and Golden Valley absorbs the integration costs right now for those small levels. We call it lost in the noise, but we have a certain amount of regulation we always carry anyways. Why charge these small power producers. It is an incentive.

Integration charges. Those are just simply the difference between the cost of power with and without the nonfirm resource. There shouldn't be any exclusions. It should just be the just and reasonable integration costs, the things that you have to do different, the change of wear and tear. I'm not saying that cost is higher or lower than fuel costs, but it's the fuel costs. It's the wear and tear. If there is a slight cost to regulation included in it -- and there could be some savings like we did when we evaluated the projects up font. If it's the savings in losses, you give that particular entity -- based on the location of the system, there might be some loss savings, so you would include that.

From our perspective, curtailment will be -- is appropriate. If you're taking power on an as-is, as-available basis and if it would raise the cost of power and -- like I said, I believe in those cases it would also be a negative. But like I say, I have to calculate it out a little more from what people have shared today. I've learned a little bit on that, but it shouldn't -- the whole bottom line is it shouldn't raise the rates to our members.

Curtailment would be factored into the purchase price for a long-term contract and based on that negotiation, you could pay for what you curtail, but that lowers the overall value of the product, or you could agree to a certain amount of curtailment because it raises the value. Once again, I'm not selling wind, but the factor that a wind power producer could go is, okay, my guess is they won't have to curtail as much as they would. So I'll take the higher price with that certain amount of curtailment, and they could make money. But no matter what, they're going to be held whole, because essentially if we pay for the curtailed power, it lowers the overall value and we would drop the price. Once again, that's negotiation. So who knows how the negotiation would go. But from my perspective, from Golden Valley's perspective, that's how we see it working out.

Golden Valley opposes the independent monitor mediation. Dean mentioned it with APA. There's already an alternate dispute resolution process, so there's enough in there. It would raise costs and just put another thing that would have to be absorbed. Somebody would have to pay for the mediation, whether we shared the cost or it all went to the utility, and those costs would be passed on to our ratepayers. There's no real reason to have it since there's already a process in place.

The key point I wanted to finish with is cost of power is a pass-through. We're a co-op. We're not for profit. What our cost of power is, it's passed through to our members. As a manager, and I believe I am an efficient manager and our power supply manager and stuff, we're always trying to reduce our cost of power. So when you're dealing with a PURPA QF -- and they stated it themselves and FERC states it. This should be rate neutral to our members.

So Golden Valley is willing to pay power from any QF that comes on our system, but only at a rate that's rate neutral or reduces our cost of power. That's what our goal is as good stewards to our members and managers. I think that's a key point that everybody agrees on. As you can see from our cost methodology that was incremental in nature, it comes up with what that value is.

I believe it's time for questions and answers.

ALJ ROYCE: Thank you, Mr. Wright.

Are there any Commissioner questions?

Hearing none, the hearing will be continued on Tuesday, February 4th at 10:00 a.m. It's our understanding several other -- there will be several other presentations at that time, and then Alaska Environmental Power will also have an opportunity to reply to the comments today. So the hearing will be continued.

We're off record at 20 to 5:00.

Thank you.

(Off record - 4:40 p.m.)

TRANSCRIBER'S CERTIFICATE

I, Leslie J. Knisley, hereby certify that the foregoing pages numbered 2 through 247 are a true, accurate, and complete transcript of the Public Hearing of the Regulatory Commission of Alaska held on January 29, 2014, transcribed by me from a copy of the electronic sound recording to the best of my knowledge and ability.

____________	____________________________________
Date	Leslie J. Knisley, Transcriber